PROJECT TO DEMONSTRATE FEASIBILITY OF GAS PRODUCTION WITH SENSITIVITIES ON PRODUCTION SCHEMES ON STERLING B4 SANDS FORMATION

By

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Abstract

The Sterling B4 reservoir is a low-relief anticline structure underlain by a weak aquifer located on the Kenai Peninsula of Alaska. This dry gas-on-water reservoir, holding approximately 13.9 BCF, has experienced challenges since its first development in the 1960s. The gas-water contact is very mobile and easily influenced upward by gas production. All four wells, largely producing in succession of one another, have experienced excessive water production which killed gas production. Faulty drilling and completion work exacerbated the challenges associated with bringing the gas to market.

This project covers an effort to develop the Sterling B4 and determine feasible alternatives for commercialization. Those alternatives include infill drilling, variable production, and co-production. Co-production is a method by which gas is produced from a single upper perforation and water is produced from a lower perforation; each of the streams are produced independently by mechanical means which utilize packers and tubing.

The only feasible alternative found by this study is co-production. Of the two co-production methods analyzed, the highest ultimate recovery includes the utilization of an existing vertical well perforating the upper portion of the reservoir for gas production and a new lower horizontal well perforating the water zone to control the gas-water contact. Modeled production schemes proved the gas-water contact was able to be controlled from upward mobility by maintaining a threshold pressure delta between the bottom-hole pressures of the two producing wells. Utilizing co-production in this manner yielded incremental benefit of over 2 BCF until shut-in limits were triggered.

Economic analysis of the project has proved bringing the gas to sales presents a significant prize able to support production and able to support facility operational expense despite no other revenue streams. Should other nearby formations demonstrate sufficient targets the economic case would be enhanced and present an even greater prize.

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1.0 Introduction

The Sterling formation is a dry gas on water reservoir located on the Kenai Peninsula of Alaska, near the city of Soldotna. Gas production has proved challenging: reserves have been exploited to limited amount since first discovery in 1961. Efforts have only recovered 3.8 BCF (27%) of original gas in place (OGIP). Contributing factors include inadequately performed drilling and casing, completions, reservoir management practices, and excessive water production.

Waterdrive gas reservoirs typically achieve an ultimate recovery of at least 35% of OGIP. Therefore, the reservoir represents a significant yield of at least an additional 1.0 BCF if the challenges from past efforts can be adequately understood and either avoided or resolved through technical solutions. This project will articulate those challenges and provide recommendations on how best to navigate them and result in a successful commercialization of the Sterling formation.

1.1 Structure Overview

The Sterling B4 reservoir is a low-relief anticline structure underlain by an aquifer. Type logs available from the Alaska Oil and Gas Conservation Commission (AOGCC) identify the Sterling B4 sands seen below in Figure 1.

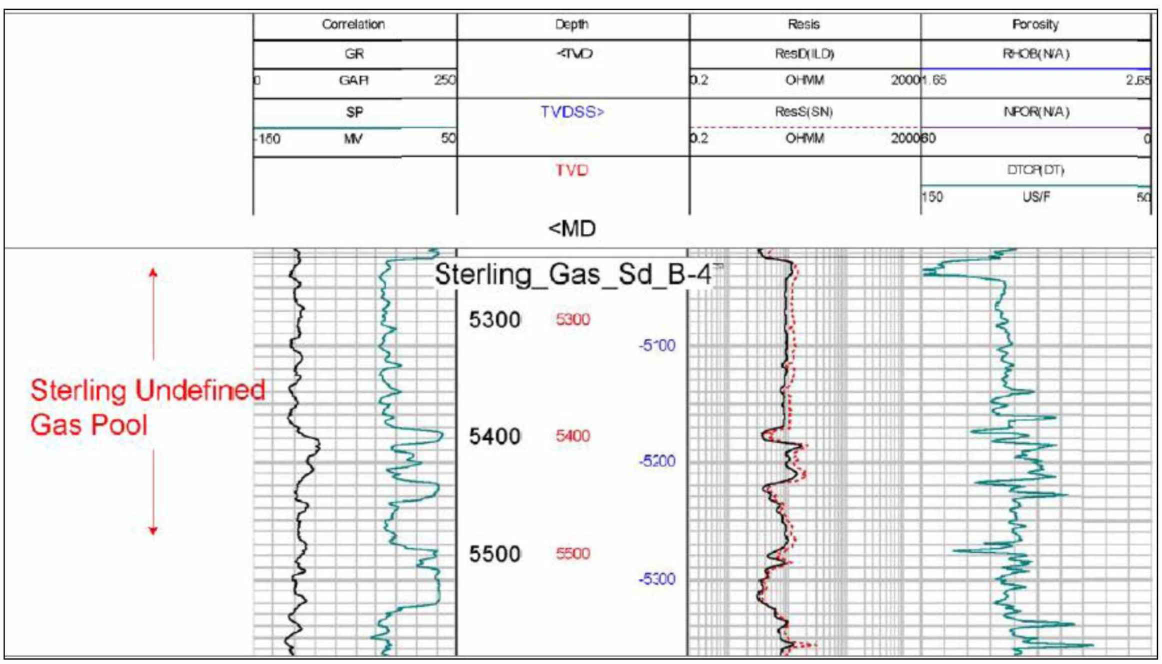

Figure 1. Type log of the Sterling B4 formation.

1.2 Well History Overview

The Sterling Unit has seven wells drilled within its lease. These wells penetrate three horizons: the Sterling, Beluga, and Tyonek formations. Because this study is exclusive to the B4 sands in the Sterling formation, well histories will likewise focus on events relating to the

B4 sands and not other formations. Of these wells, most have encountered numerous challenges, ranging from pinched casings and failed packers to watered-out sands. These challenges merit a closer review to better understand how to provide solutions.

The first well in the B4 sands unit was SU 23-15 in 1961. It briefly produced gas, but then began producing excessive amounts of water, which led to it being shut-in in 1966. Well 43-09 was drilled in June of 1963 and produced dry gas flowing 3-5MMCFD for two hours. An open flow potential test was performed prior to the well being shut-in. Subsequent work brought 43-09 production online to metering facilities in October of 1966. The market for this gas was lost in 1986 and the well was shut-in.

It was again tested in September of 1993 to determine if the projected production rate of 3 MMCFD could be sustained without producing water. The well produced no significant amount of water, but a hydrate plug was formed in the wellbore approximately 150 feet subsurface, which extended the test from three days to five.

Well 32-09 was permitted in 1998 to penetrate the Sterling formation. Gas production was initially satisfactory with production rates between 1 and 2 MMCFD, but subsequent and excessive water production drove efforts toward water disposal options. The well was shut-in in early 2005.

The well was later used to target the Upper Beluga formation (which lies above the Sterling B4 sands) in 2013 when completion tools were unable to be pulled. The tools became stuck in a tubing patch and eventually dislodged but apparent damage to the patch has prohibited any slicklines from penetrating through the patch to retrieve the tools. Repairs would need to be made if this well was utilized for any further work in the Sterling B4 formation.

Water disposal plans began in 2000: Well 43-09 was utilized by converting it into an injector. Water injection began after surface facility construction was completed in February of 2004. The water was injected into the upper gas-bearing portion of the B4 sands, the same perforation from which the well produced, for unknown reasons. This is thought to be a contributing factor to a water saturation gradient from the top to the bottom of the gas-bearing zone, which will be later discussed.

Well 43-9X was drilled in June and July of 2007 on Sterling Pad 43-9 and targeted the Sterling B4 sands exclusively. This effort resulted in a notable finding: the open hole logs appeared to be gas bearing, but the repeat formation tests indicated a water saturation gradient from top to bottom. Dealing with the water throughout this zone was found to be the most challenging element to bringing the B4 gas to sales.

The intent with this well was to utilize a production method referred to as dual production, or co-production. This production strategy controls the location of the fluid contacts which allows the gas zone to be targeted more effectively. This is done by perforating two zones of the reservoir with each stream mechanically isolated through packers and tubing assemblies. Each fluid stream is independently controlled.

This effort failed because of a damaged gravel packer that allowed water to cone up into the gas production zone. Co-production was not successfully implemented for this application. In addition to inadequate completions, the primary challenge to successfully bringing B4 gas to sales lies in water coning. Efforts to control the water contact have not been successful and water disposal is thought to have led to a water saturation gradient through the gas zone.

1.3 Identification of Pay Zones

All wells in the Sterling Field were logged with wireline instruments that produce induction and sonic logs. The induction log plotted spontaneous potential (SP) against resistivity and conductivity while the micro log plotted SP against interval transit time. The top of the Sterling Formation is identified by the well log from Well 43-9X shown in Figure 2. Of note, the SP plot values are inverted on this figure due to an error in the data collection.

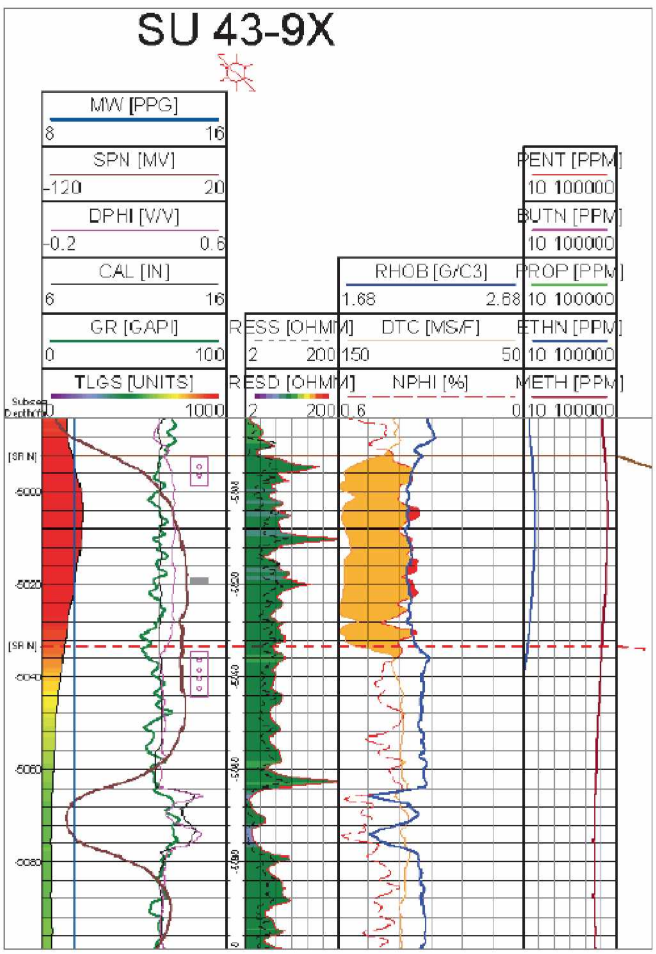

Figure 2. Type log from Well 43-9X.

The top of the formation is identified at 4,992 feet True Vertical Depth (TVD). The SP plot (brown solid line on the left) deviates to the right , which demonstrates a less shaley, or clean, sandstone with a higher porosity. This description is typical throughout 4,992-5,050 ft TVD and 5,080-5,104 ft TVD. The resistivity log shows a decrease in the formation's electrical conductivity, indicating an increase in hydrocarbon presence. Therefore, a productive horizon is determined by the identification of sandstone and increased resistivity. This method is used to similarly identify the gross pay zones in the other four wells. The gross and net pay zones (sandstones) are identified in the Table 1.

	Well				
	43-9X	43-09	32-09	23-15	41-15
Top of Formation (TVD)	4992	5005	5013	5025	5037
Gas/Water Contact* (TVD)	5041	5041	5041	5041	None
Bottom of Formation (TVD)	5112	5108	5108	5172	5124
Gross Pay (ft)	120	103	95	147	87
Net Pay (ft)	49	36	28	16	0

*Original GWC

Table 1. Formation characterization from wells.

These boundaries are then mapped against the directional surveys associated with each well. This is done by plotting the TOF, BOF, and GWC boundary locations as horizontal offsets from the wellhead surface location to develope a gross structure. This result is shown in Figure 3. A larger plot is attached as Appendix A.

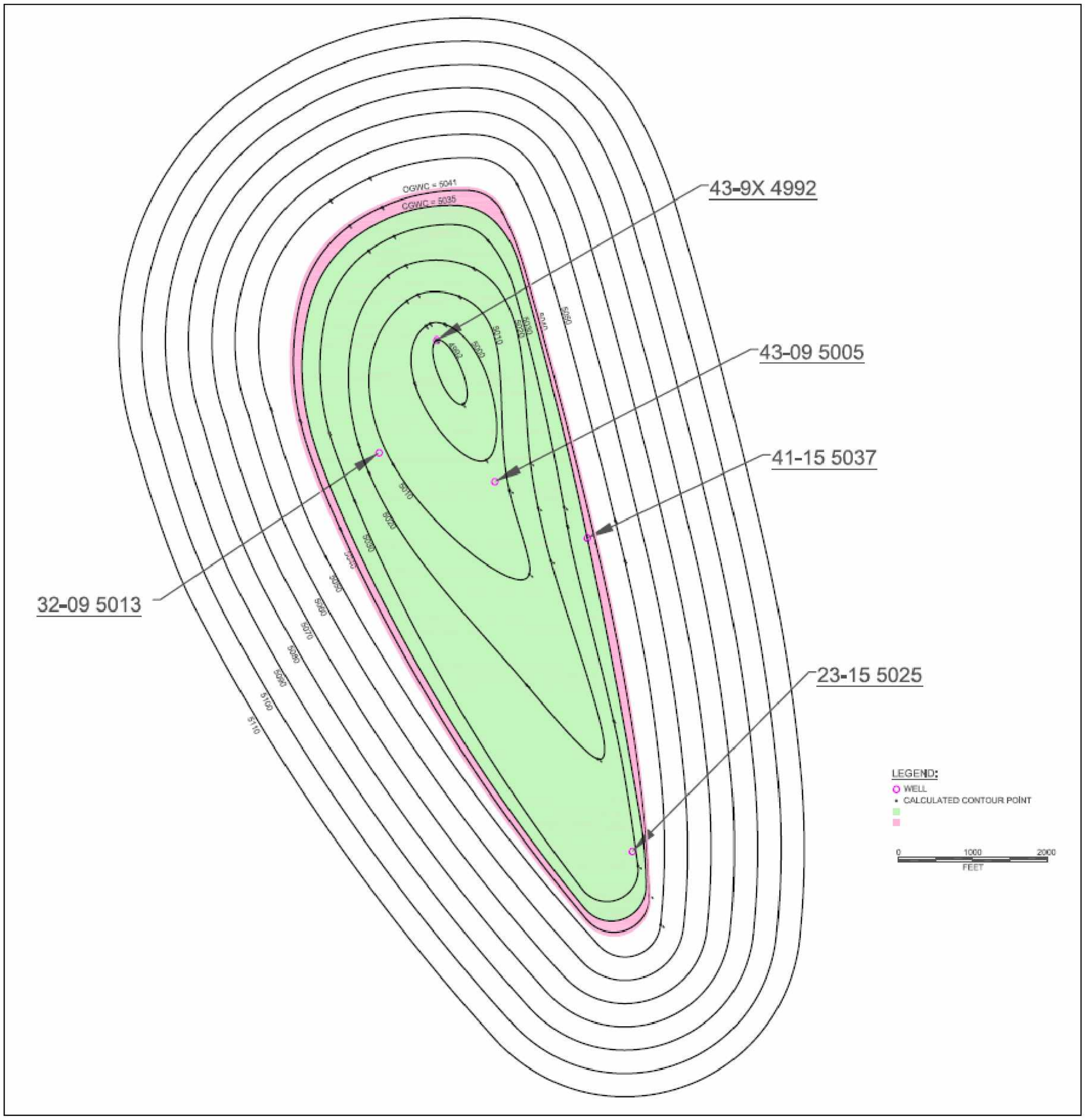

Figure 3. Structure formation from type logs.

1.4 Identification of OGIP by Volumetrics

The contour lines defining the structure are then used to determine OGIP by volumetrics from the top of the reservoir to the GWC contact. The structure volume within the reservoir is calculated using the average area method between contour lines and is shown in Table 2.

Step	Contour	Area	Average Area	Height	Volume
	(ft)	(ft^2)	(ft^2)	(ft)	(ft^3)
1	4990	237,209	847,335	10	8,473,350
	5000	1,457,461			
2	5000	1,457,461	3,338,069	10	33,380,685
	5010	5,218,676			
3	5010	5,218,676	8,184,368	10	81,843,680
	5020	11,150,060			
4	5020	11,150,060	15,687,855	10	156,878,545
	5030	20,225,649			
5	5030	20,225,649	23,594,696	10	235,946,955
	5040	26,963,742			
6	5040	26,963,742	26,975,560	1	26,975,560
	5041	26,987,378			

Table 2. Volume calculations for volumetrics.

The sum of the volumes of the structure is 543,498,755 ft^3.

OGIP is then determined using the below equation.

$$G = \frac{Ah\phi S_{gi}}{B_{gi}} \tag{1}$$

Where G is the original gas in place, Ah is the gross volume, □ is the structure porosity, and B_{gi} is the original gas formation volume factor. S_{gi} is the initial gas saturation.

The porosity of the formation is estimated to be 0.26 based upon publically available information from the AOGCC.

S_{gi} is determined by the following equation,

$$S_{gi} = 1 - S_{wi} \tag{2}$$

where S_{wi} is the initial water saturation. Based upon information from the AOGCC, the initial water saturation and is assumed to be 0.40. The formation volume factor is determined by using equation 3. Compressibility factor is 0.87; temperature is 103F, or 562.7 Rankine; and pressure is 2,266 psi.

$$B_{gi} = 0.0282793 \, \frac{zT}{p} \, rcf/scf \qquad (3)$$

$$B_{gi} = 0.0282793 \frac{0.87(562.7)}{2{,}266 \, psi} rcf/scf = 0.006109 \, rcf/scf$$

Therefore:

$$G = \frac{543{,}498{,}755 ft^3 (0.26)(1.0-0.4)}{0.006109 \frac{rcf}{scf}} = 13{,}878{,}835 \, mscf$$

Therefore, the OGIP is determined to be approximately 13.9 BCF by volumetrics. This number will be confirmed by material balance.

1.5 Identification of OGIP by Material Balance

The material balance method will utilize the production data shown in Figure 4.

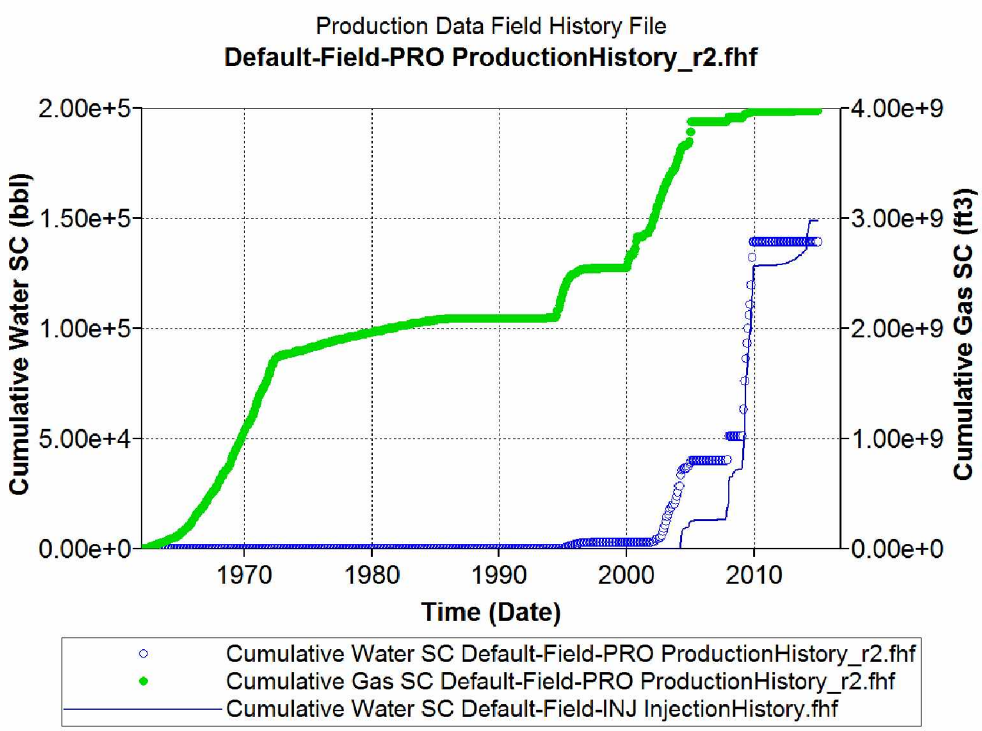

Figure 4. Production and injection history of the Sterling B4 sands

Published in 1994, Walsh fully matured the material balance equation. His development of the equation, as applied to the Sterling reservoir, is summarized below.

A volume balance gives the following:

$$V_p = (Volume\ of\ free\ oil\ phase) + (Volume\ of\ free\ gas\ phase) + (Volume\ of\ free\ water\ phase) \quad (4)$$

Where V_p is the reservoir pore volume. Because the Sterling Field is dry gas on water, Walsh simplifies the material balance equation to the following:

$$B_{gi}G = B_gG - G_pB_g + \Delta W \quad (5)$$

Where B_{gi} is the initial gas formation volume factor, G is the original gas in-place, Bg and G_p are the gas formation volume factor and cumulative gas production, respectively, at the time being considered. And ΔW is:

$$\Delta W = (W_i - W_p)B_w \quad (6)$$

Where W_i is water influx volume, W_p is the cumulative water produced, and B_w is the water formation volume factor.

Fundamentals of Reservoir Engineering (Towler) gives the full form of the material balance in the following manner:

$$F = N_{foi}E_o + G_{fgi}E_g + \Delta W + (N_{foi}B_{oi} + G_{fgi}B_{gi})E_{fw} \quad (7)$$

Where,

$$F = N_p\left(\frac{B_o - R_sB_g}{1 - R_vR_s}\right) + G_p\left(\frac{B_g - R_vB_o}{1 - R_vR_s}\right) \quad (8)$$

$$E_o = \left[\frac{B_o(1 - R_vR_{si}) + B_g(R_{si} - R_s)}{1 - R_vR_s}\right] - B_{oi} \quad (9)$$

$$E_g = \left[\frac{B_g(1 - R_sR_{vi}) + B_o(R_{vi} - R_v)}{1 - R_vR_s}\right] - B_{gi} \quad (10)$$

$$E_{fw} = \left(\frac{c_f - c_w S_{wi}}{1 - S_{wi}}\right) \Delta p \tag{11}$$

$$\Delta W = (W_i - W_p) B_w \tag{12}$$

Where c_f is formation compressibility, c_w is water compressibility, $\Delta p = p_i - p$, p_i is the initial reservoir pressure and p is the reservoir pressure at the time being considered.

Because no free oil-phase exists in the Sterling reservoir, N_{foi}, R_v, and R_s may be removed from the following equation:

$$F = G_{fgi} E_g + G_{fgi} B_{gi} E_{fw} + \Delta W \tag{13}$$

Which then may be simplified to the following

$$F = G_p B_g \tag{14}$$

and

$$E_g = B_g - B_{gi} \tag{15}$$

Therefore the full material balance equation in a form applied to the Sterling field develops into the following

$$F = G_{fgi}\left(B_g - B_{gi}\right) + G_{fgi} B_{gi} \left(\frac{c_f - c_w S_{wi}}{1 - S_{wi}}\right) \Delta p + W_p B_w \tag{16}$$

Finally, because this reservoir received water injection, W_p will be replaced with W_p-W_i. W_i will be considered a summation of water influx and water injection in later use.

$$G_p B_g = G_{fgi}\left(B_g - B_{gi}\right) + G_{fgi} B_{gi} \left(\frac{c_f - c_w S_{wi}}{1 - S_{wi}}\right) \Delta p + (W_p - W_i) B_w \tag{17}$$

Thus, the OGIP may be determined by solving for G_{fgi}.

$$G_{fgi} = \frac{G_p B_g - (W_p - W_i) B_w}{\left[(B_g - B_{gi}) + B_{gi}\left(\frac{c_f - c_w S_{wi}}{1 - S_{wi}}\right)\Delta p\right]} \tag{18}$$

Using production data, the above equation may be solved, but the presence of water influx must be determined. Towler gives the following equation to determine whether a reservoir is volumetric:

$$G_{fgi} = \frac{G_p}{1-\left(\frac{pz_i}{p_i z}\right)} \tag{19}$$

Where z and z_i are the compressibility factors at the considered time and at initial conditions, respectively.

The compressibility factor at initial conditions is determined to be 0.87. Similarly, the z factor for present conditions (same temperature and reservoir pressure of 1,973 psia) is determined to be 0.88. The question of whether the reservoir is volumetric may now be determined.

$$G_{fgi} = \frac{3{,}884{,}340\ mscf}{1-\left(\frac{1{,}973\ psia(0.87)}{2266\ psia\ (0.88)}\right)} = 27{,}905{,}338\ mscf$$

Due to the large degree of difference between this result and the volumetric estimate (13.9 bcf), a water influx is suspected.

1.6 Identification of Drive Mechanisms

Confirmation of water influx may be determined by use of a waterdrive diagnostic plot, where F/Eg is plotted against Gp. If the line is horizontal, then the reservoir is volumetric. This plot is constructed using the information in the below table. For this method, the z factor was more precisely calculated using the EOS developed by Dranchuk and Abou-Kassem and seen below.

$$z = 1 + \left(A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}{}^3} + \frac{A_4}{T_{pr}{}^4} + \frac{A_5}{T_{pr}{}^5}\right)\rho_{pr} + \left(A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}{}^2}\right)\rho_{pr}{}^2 - A_9\left(\frac{A_9}{T_{pr}} + \frac{A_8}{T_{pr}{}^2}\right)\rho_{pr}{}^5 + A_{10}(1 + A_{11}\rho_{pr}{}^2)\left(\frac{\rho_{pr}{}^2}{T_{pr}{}^3}\right) \times e^{(-A_{11}\rho_{pr}{}^2)} \tag{20}$$

Where

$$\rho_{pr} = \frac{0.27 p_{pr}}{z T_{pr}} \tag{21}$$

And constants A_1 through A_{11} are A_1 = 0.3265, A_2 = -1.0700, A_3 = -0.5339, A_4 = 0.01569, A_5 = -0.01565, A_6 = 0.5475, A_7 = -0.7361, A_8 = 0.1844, A_9 = 0.1056, A_{10} = 0.6134, and A_{11} = 0.7210.

Table 3 captures the calculated information and is inclusive of data before water injection began in 2004.

Pressure	Gp		Bg	p/z	Eg	F=GpBg	F/Eg
psia	mmscf	z	rcf/scf	psia	rcf/scf	mrcf	mmscf
2266.00	0.00	0.848	0.001053	2671.540	0.000000	0.000000	-
2243.86	51.15	0.848	0.001085	2644.799	0.000031	0.055472	1,780
2116.51	607.74	0.850	0.001130	2489.523	0.000077	0.687040	8,917
1982.71	2095.11	0.853	0.001210	2324.159	0.000156	2.534593	16,212
1948.26	2538.70	0.854	0.001277	2281.440	0.000224	3.242772	14,483
2005.35	2723.23	0.853	0.001188	2352.183	0.000135	3.236026	23,993

Table 3. Material balance information for use in waterdrive diagnostic.

The data are then plotted in Figure 5 to determine the presence of waterdrive.

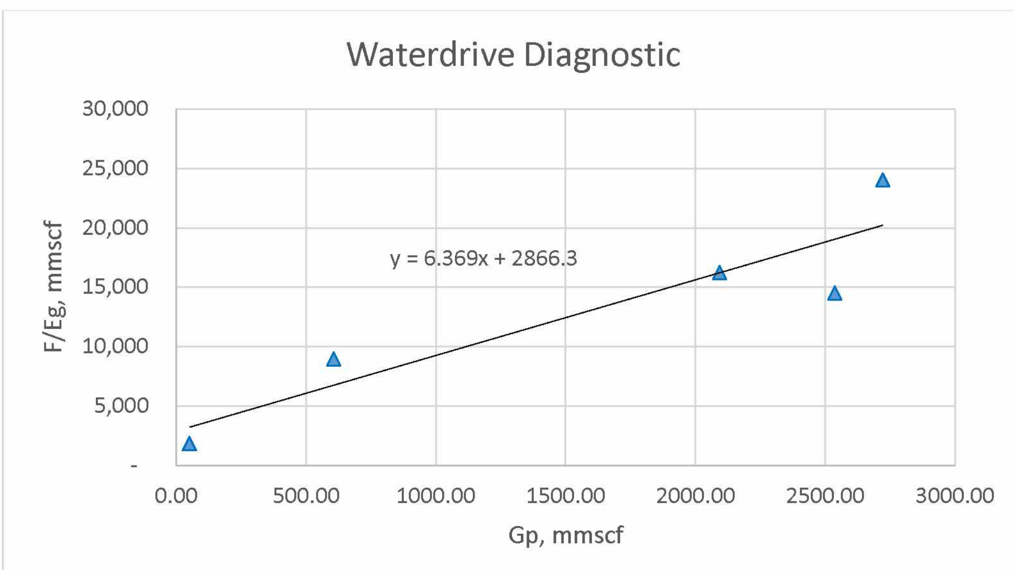

Figure 5. Waterdrive diagnostic plot.

Because the line in the plot above is not horizontal, the reservoir is confirmed to be non-volumetric with a waterdrive. This may be further illustrated with the p/z plot in Figure 6.

Because the *p/z* ratio does not decline linearly with cumulative production, water influx is confirmed.

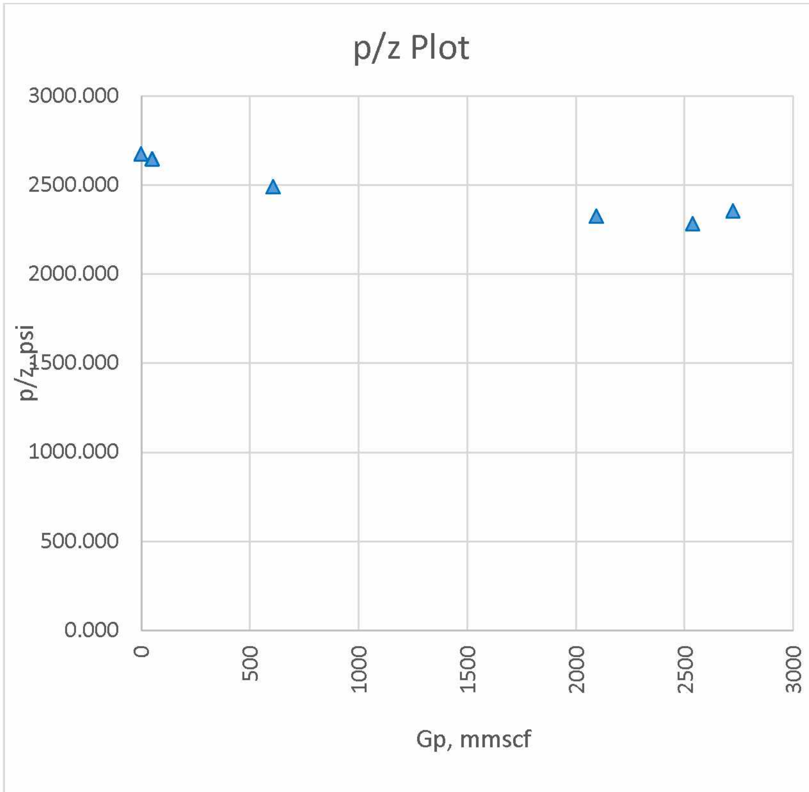

Figure 6. Plot demonstrating aquifer influx.

2.0 Objectives

The primary objective of this study is to demonstrate successful commercialization of the Sterling B4 gas. Feasibility will be determined by a series of three objectives. The first is to demonstrate a reservoir modeling scenario which allows probable incremental recovery of at least 1 BCF of remaining gas in place. The second objective is to identify a series of production strategies that demonstrate technical feasibility, as defined by recovering at least 1 BCF. The third objective is to determine optimal economics among technically feasible strategies.

3.0 Literature Review

Fluid contact control has been successfully utilized in gas-on-oil and oil-on-water reservoirs, but little discussion exists in applying this method to gas on water reservoirs. Arcaro and Bassiouni (1987) determined co-production to be feasible in increasing gas recovery by as much as 20% in water-drive gas reservoirs, which generally have a much lower recovery rate than depletion drive reservoirs. Reservoir selection criteria includes fields which have not watered out and have existing watered-out wells to use as water producers. Utilizing existing wells and availability of surface disposal will enhance economic potential. Their findings identified water production rate as the most sensitive variable.

Bowlin, *et al* (1997) successfully used this method in an oil-on-water reservoir that experienced water coning issues for many years, prior to the implementation of co-production.

Shirmin and Wojtanowicz (1997) determined control of the contact remains so long as the pressure drop in the water zone due to production equals the pressure drop in the oil zone when co-producing in an oil-on-water reservoir. Thus, production rate of the water is a key variable needing to be optimized.

Wojtanowicz, Xu, and Bassiouni (1991) simulated an oil-on-water reservoir and determined that only three of the seven coning variables can be controlled. The seven total variables affecting coning are mobility ratio, oil zone thickness, ratio of gravity to viscous forces, well spacing, ratio of vertical to horizontal permeability, and well penetration and production rate. Of these seven, only well spacing, well penetration, and production rate may be feasibly controlled. The authors determined successful control of the oil-water contact required the determination of a critical oil production rate and maintaining production below that critical rate.

Swisher and Wojtanowicz (1995) successfully implemented field testing of a dual completion well in an oil-on-water reservoir. They determined water coning was preventable, and were even able to reverse a water cone after breakthrough. The key to successful implementation was maintaining the production rate below a critical rate. Above the critical rate, the system became unstable and control of the contact was lost.

McMullan and Bassiouni (2000) confirmed the water production rate as the most sensitive variable in low permeability systems with the gas production rate becoming more dominant as permeability increases. In systems where water disposal costs are minimal, gas production rates should be maximized. This work, however, related only to optimizing perforation location and gas production rates.

Armenta and Wojtanowicz (2003) explored incremental recovery associated with dual-completed wells in gas-on-water reservoirs and determined that gas recovery increases with permeability. Their effort demonstrated a clear advantage to coproduction in tight (1 md) and low pressure reservoirs. As permeability increased beyond 10 md, the advantage of coproduction over conventional production diminished to 10%.

Therefore, as permeability decreases, the production of the lighter or less viscous fluid stream is more sensitive to overall recovery. Thus, oil production rate is the controlling variable in oil-on-water co-production applications, but the water production rate is the more sensitive variable in gas-on-water co-production applications. The limiting factor in low permeability, gas-on-water systems is water disposal and is a significant factor impacting project economics.

Prior unpublished academic work was performed on the Sterling B4 sands by Mr. Lyndon Ibele, a petroleum engineer working for Marathon, a former owner-operator of the asset. This work targeted dual completions in the 43-9X wellbore which produced gas in the annulus while simultaneously producing water through tubing in a lower interval. Production streams would be isolated via packers located at the gas-water contact. The key to this strategy would be optimizing the water production rate to effect a well draw down sufficient to avoid water coning.

4.0 Reservoir Model Development

4.1 Introduction to CMG Builder and IMEX

This project will use Computer Modelling Group Ltd. (CMG) Builder and IMEX reservoir simulator, commercially available software, to develop a model simulating the Sterling B4 sands formation and run prediction cases to determine the optimal production strategy to bring the gas to sales.

4.2 Structure and Well Locations

A contour map for this project was developed in the Atlas Boundary format by utilizing the boundary information determined in Section 2.3 Identification of Pay Zones. These boundaries are then mapped against the directional surveys associated with each well. This is done by plotting the TOF, BOF, and GWC boundary locations as horizontal offsets from the wellhead surface location, thereby developing a gross and net pay structure. This result is shown in Figure 7 and a larger plot is attached as Appendix A. Well 41-15 was utilized to develop the structure of the reservoir, but is not completed in the B4 sands zone and is therefore not included in the production analysis.

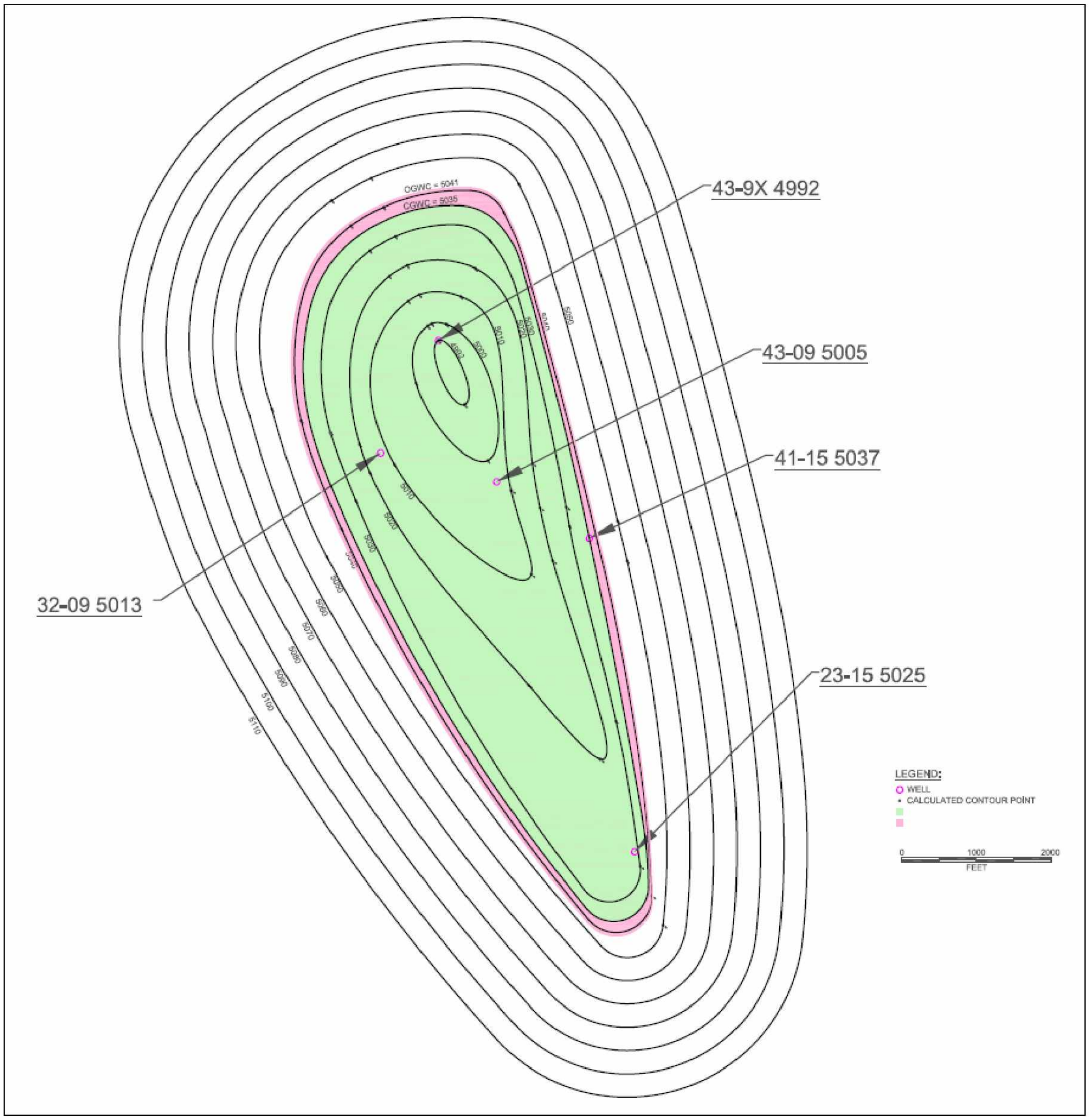

Figure 7. Structure formation developed into Atlas Boundary map file.

4.3 Model Grid and Properties

The contours developed from the well logs were then exported into an Atlas Boundary contour file and an associated grid thickness file was developed. These two files were imported into CMG Builder and merged with a Cartesian grid of 45x80x22 to develop the structure seen in Figure 8.

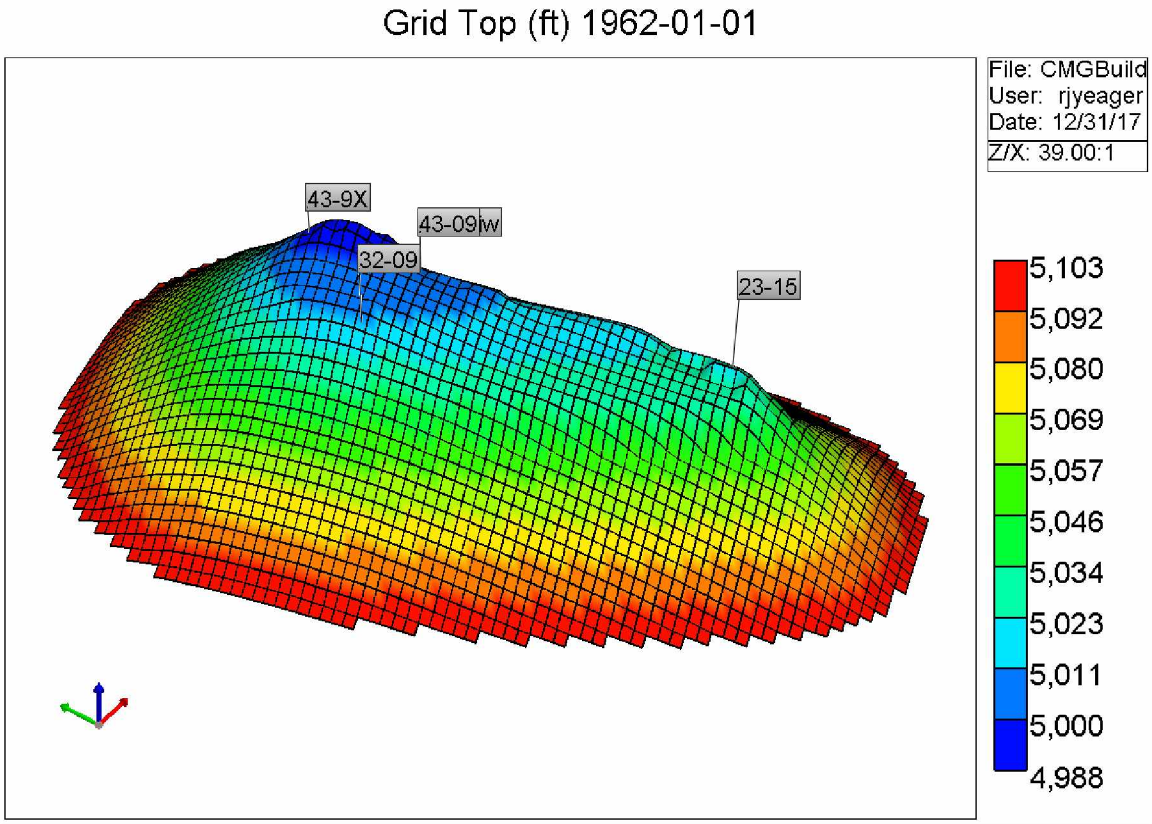

Figure 8. Structure formation after imported into CMG Builder and merged with depth information from second Atlas Boundary map file.

The reservoir was modeled with a non-orthogonal corner point grid. Porosity is uniform at 0.286, k_i *and* k_j were determined during history match (core analyses for the reservoir were not available for use) and assumed to be 60 md, with a k_v/k_h ratio of approximately 0.25.

Water influx was modeled with an aquifer using the Fetkovich method. The depth was 50 ft, a porosity equal to the structure, and a radius of 15,000 ft. CMG Builder developed the PVT properties based upon a gas gravity of 0.556 and a reservoir temperature of 103F.

The relative permeability curves proved to be the most sensitive variables when history matching for water production. Actual relative permeability curves were not available for use and were thus systematically determined during history match. The relative permeability curves used in the model are seen in Figure 9 and were determined using the following mathematical relationships:

$$K_{rg} = [(S_G - S_{GCR})/(1 - S_{GCR})]^{Ng} \quad (21)$$

$$K_{rw} = [(S_w - S_{WCR})/(1 - S_{WCR})]^{Nw} \quad (22)$$

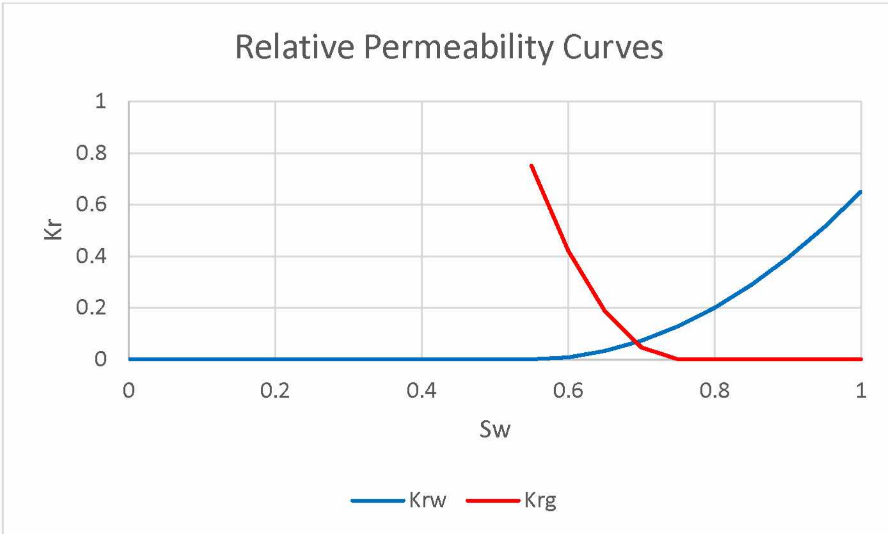

Figure 9. Relative permeability plot.

The above plot has an S_{gcr} of 0.25, N_g of 2, S_{wcr} equal to 0.4, and N_w of 2.

4.4 History Match

The history match process began with matching the historical reservoir pressure, shown in Figure 10.

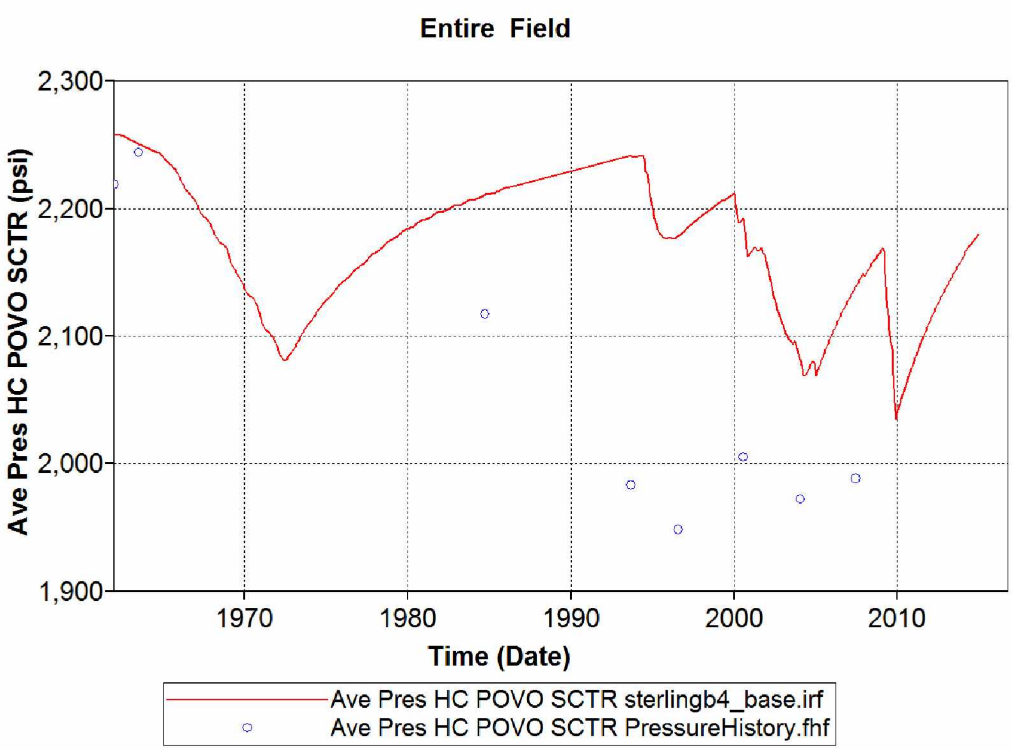

Figure 10. Pressure history match plot.

Aquifer support was modified as needed during the history match process to aid in pressure maintenance. Historical production information was imported into the model and field history files were created. The relative permeability curves were modified to match the water production history: the gas production was controlled and water production varied based upon the relative permeability curves.

Figure 11 shows the match against historical production and injection information. Several items are noted: the model begins producing water much earlier than the historical information, and the gas production is higher than historical in 2010.

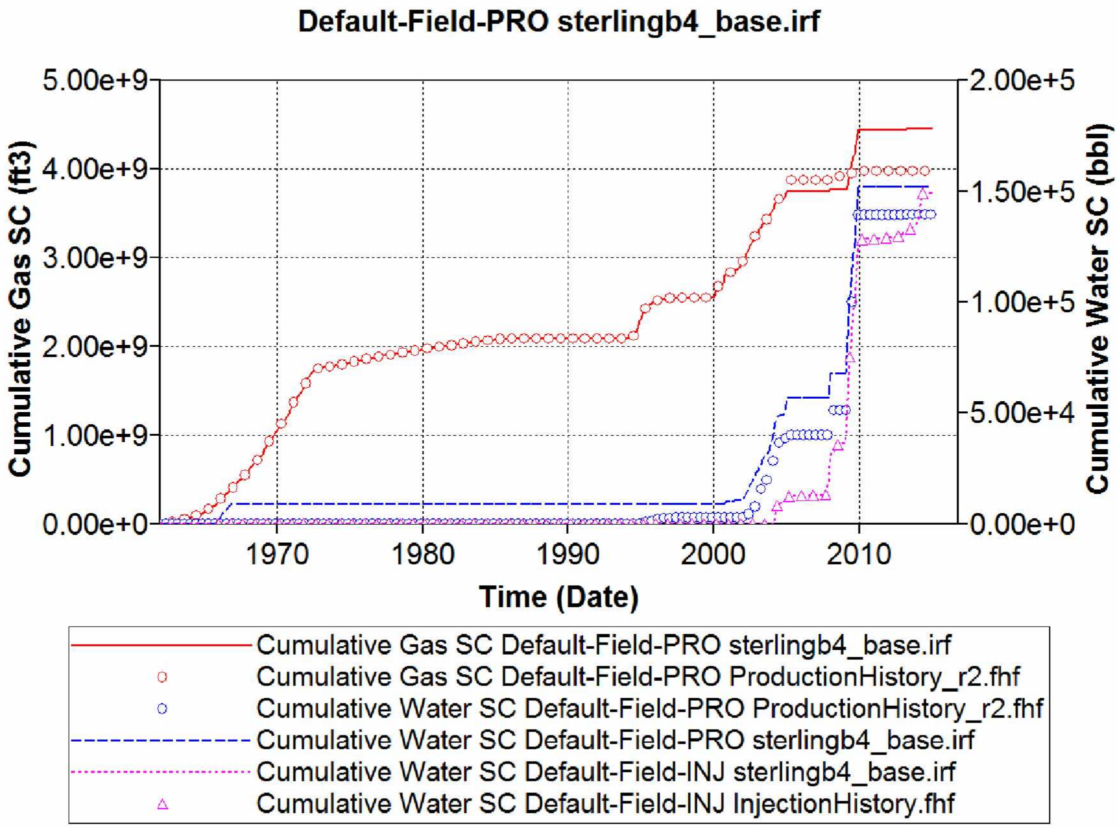

Figure 11. Production history match plot.

The production history made available for use did not demonstrate any water production from the well that first produced from the B4 sands. Well 23-15's history file, however, contained anecdotal evidence that it was shut-in due to excessive water production. Therefore, water production from 23-15 is a reasonable assumption.

Well 43-9X was responsible for the abberation in gas production in 2010. This well was completed as a co-production well, meant to control the gas/water contact with perforations in the water and gas zones. Production streams from these zones were isolated by a gravel packer and producing gas through the annulus from the upper perforation and through a tubing string extending through the gravel packer to the lower perforation.

This completion was modeled with two wells. The upper string controlled by gas production and the lower controlled by water production. The lower string produced both gas and water, which results in a cumulative production that is in excess of historical production.

Finally, the original GWC was identified at 5,041.0 ft SSTVD. This was raised to 5040.2 ft SSTVD during the history match.

4.5 Reservoir Model Initial Conditions

All cases start at time zero (0) on January 1, 2015 and run for 20 years. Gas production wells have a shut-in limit of 100 bbls/d.

4.6 Sensitivities

4.6.1 Field Abandonment

This case considers no additional development of the field and sale of the lease. Based upon an estimated 10 BCF of remaining gas in-place, a net sale of $2MM is assumed to be realized with the sale of the asset.,

4.6.2 Infill Drilling

This case considers a new vertical and a new horizontal well in the Sterling B4 sands.

New Vertical Well

This case considers a vertical well perforated in the top 5 feet of the reservoir. This well would be located at the top of the structure as seen in Figure 12.

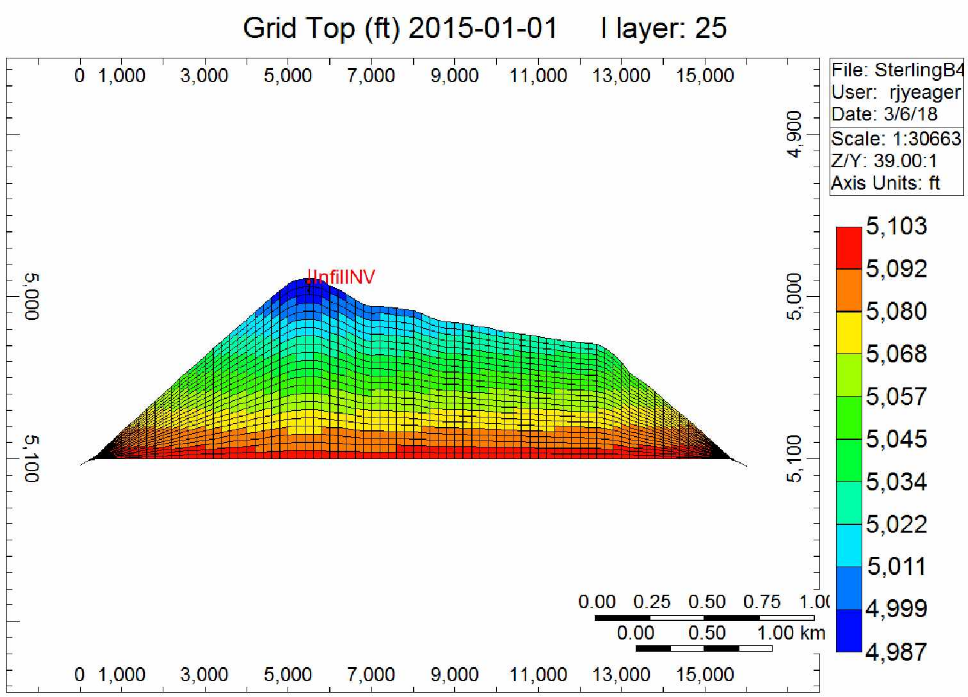

Figure 12. Prediction case with new vertical well shown perforating the top two layers of the model.

New Horizontal Well

A horizontal well was modeled to perforate the uppermost part of the reservoir as seen in Figure 13.

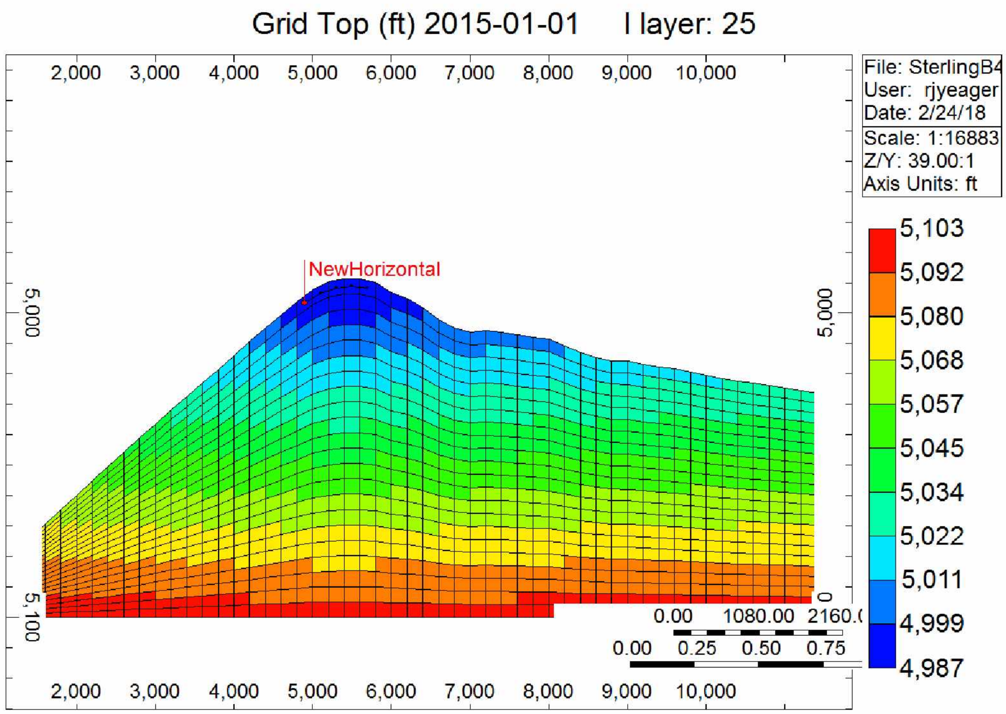

Figure 13. Prediction case with new vertical well shown perforating the top layer of the model.

4.6.3 Utilize Existing Well

This case analyzed a single existing well, 43-9X, for sensitivity to production rates. This well has an upper and lower perforation previously used to implement co-production. This case will open the upper perforation only and produce gas until the rate of water production reaches 100 bbl/d, at which point the well is shut-in. Production rate was stepped from 200 to 1000 mscf/d at 200 mscf/d.

4.6.4 Co-Production

Several different co-production scenarios were modeled based upon three overall co-production strategies: new vertical well, new horizontal wells, and a new lower horizontal well with gas production from the upper perforation of existing well 43-9X.

Horizontal Co-Production

The reservoir is perforated with a horizontal well in the upper portion of the reservoir for a length of 800 feet, with a lower horizontal well perforated approximately 15 feet below the GWC. This configuration was modeled at a gas production rate of 200, 400, 600, and 1,000 mcf/d.

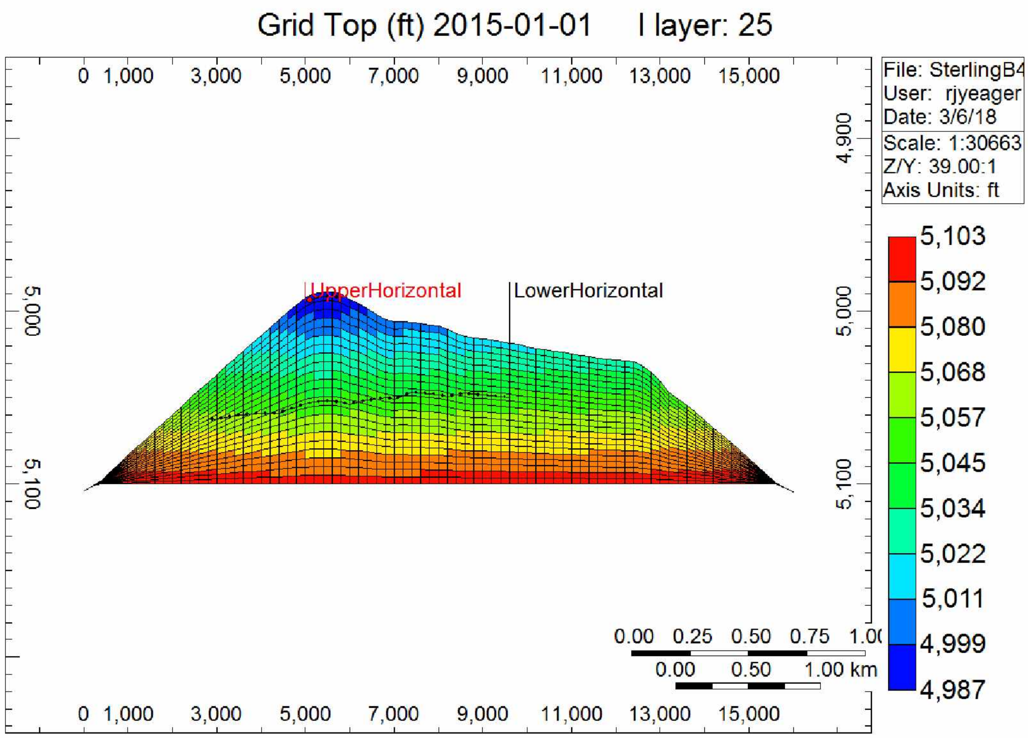

Figure 14. Prediction case with new upper horizontal well for producing gas and a new lower horizontal well for producing water to control the gas-water contact.

Vertical Co-Production

The reservoir is perforated for a length of 5 feet in the upper portion of the reservoir with a lower completion in the same well perforated approximately 20 feet below the GWC. This configuration was modeled at a gas production rate of 200, 400, 600, and 1,000 mcf/d.

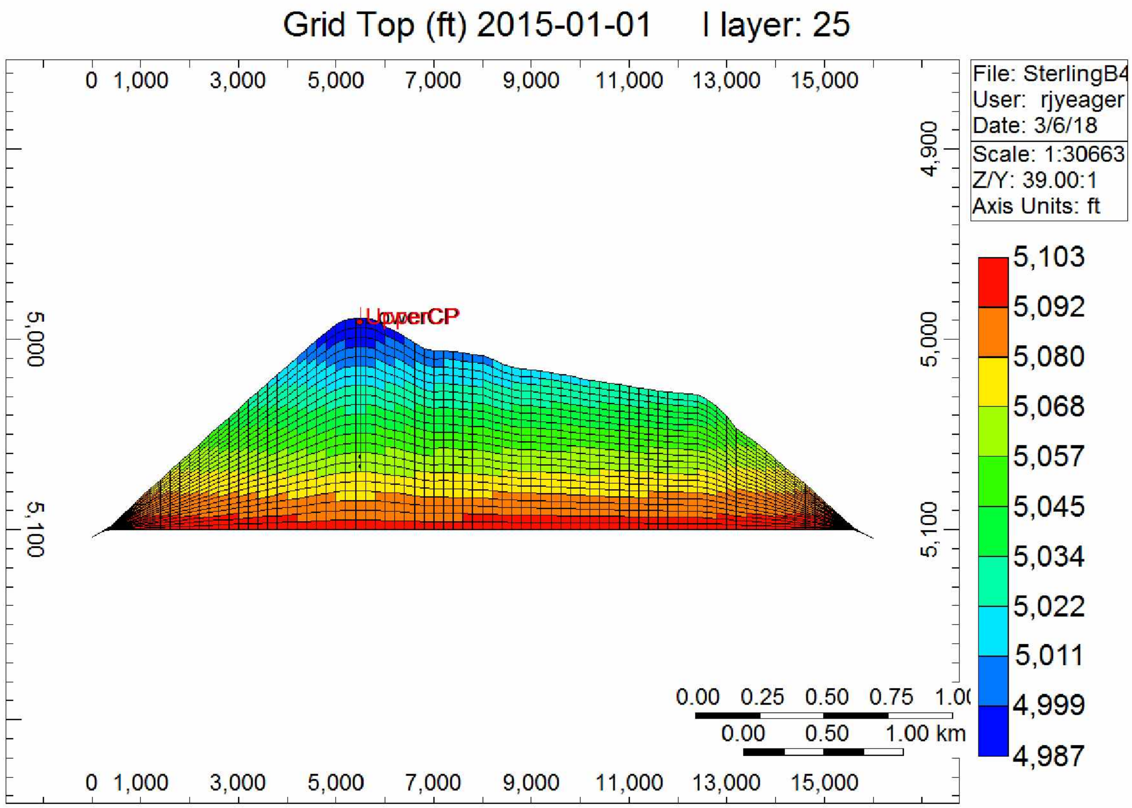

Figure 15. Prediction case with new upper vertical perforation for producing gas and a new lower vertical perforation for producing water to control the gas-water contact.

Vertical/Horizontal Co-Production

This scenario sought to enhance project economics by drilling only one new well: a horizontal well located below the GWC intended to control the contact location. Gas would be produced through the upper perforation in the existing 43-9X well. Utilizing existing infrastructure would minimize development costs to bring the gas to sales and enhance project economics.

The lower well's perforation is 20 feet below the GWC. This configuration was modeled at a gas production rate of 200, 400, 600, and 1,000 mcf/d, with each gas production rate further modeled at water production rates of 500, 1,000, and 1,500 bbl/d.

5.0 Results

5.1 Reservoir Characteristics during Production

The well history overview demonstrated many challenges, but the primary reservoir and production challenge was caring for the excess water. Despite successively drilled wells located increasingly higher within the formation, excessive water production continued to plague them all. The location and movement of the water in the model, therefore, needs to be well understood. This will ultimately determine the success of meeting this project's first objective: delivering an incremental benefit of 1 BCF of gas.

The behavior of the water had been described as being particularly sensitive to FBHP by operations personnel, as observed in the well history files. Whereas the excessive water production from Well 23-15 (shown in Figure 16, enlarged in Figure 17 showing the water coning upward, and associated gas and water production rates in Figure 18) may be explained due to its edge location and vertical proximity to the GWC (approximately 10 feet), subsequent wells centrally located with greater vertical distance from the OGWC experienced water production.

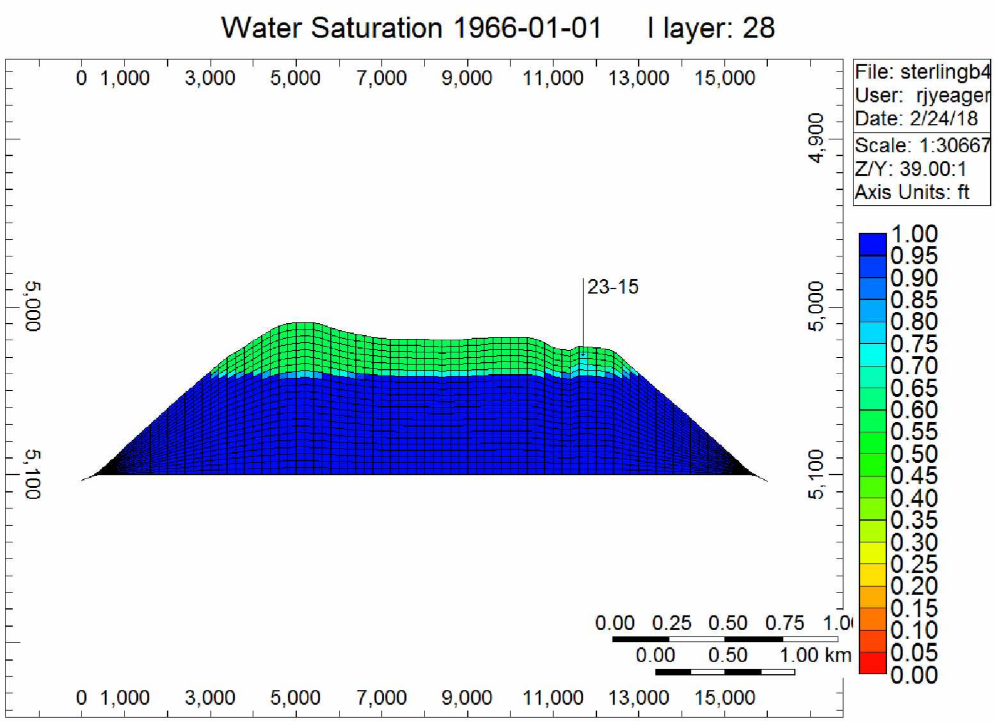

Figure 16. Well 23-15 shown with water cone effect near the wellbore.

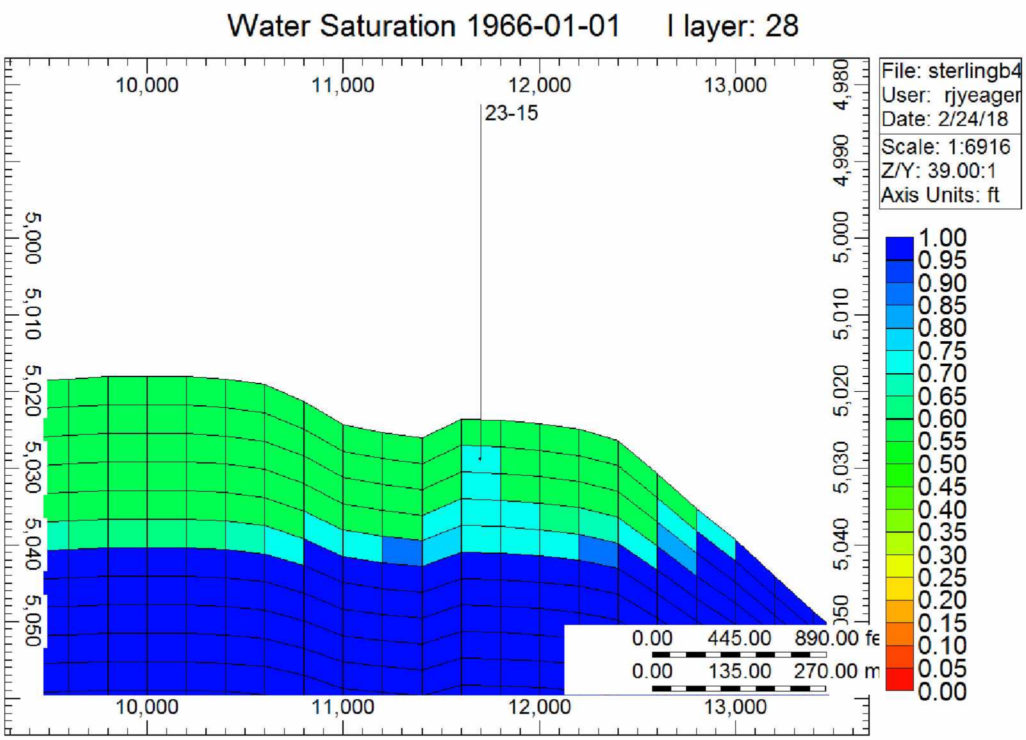

Figure 17. Well 23-15 shown with water cone effect near the wellbore.

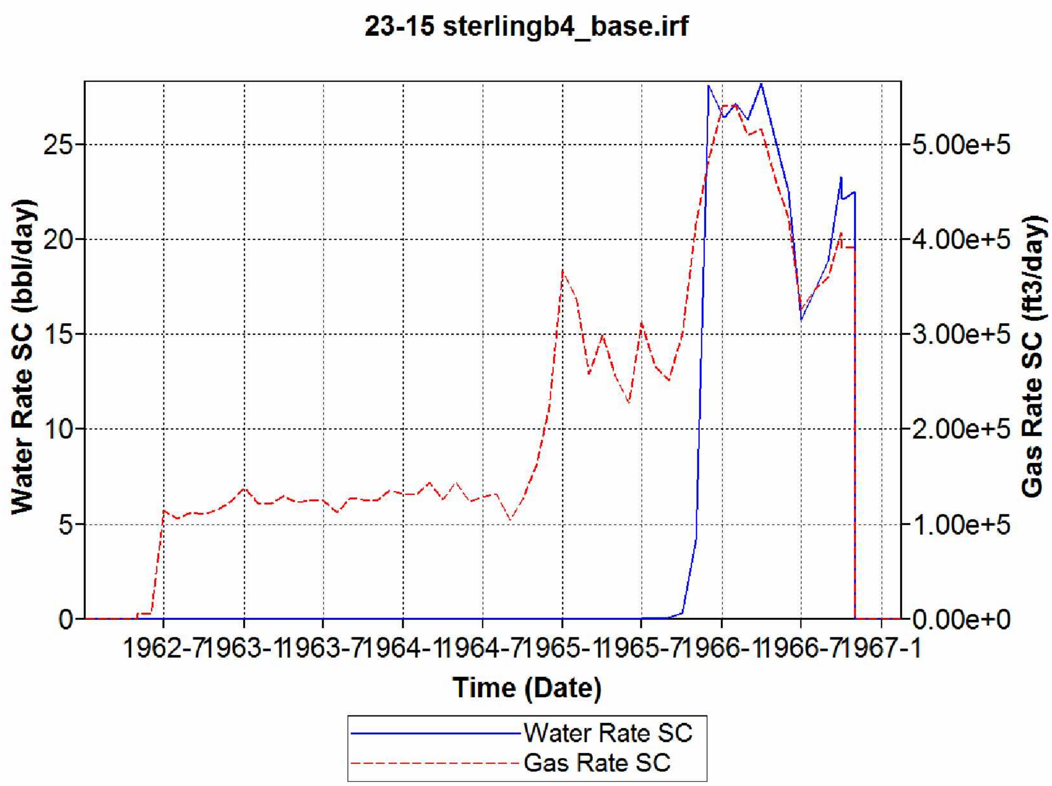

Figure 18. Water and Gas Production Rates in Well 23-15.

Well 43-09 came online just after Well 23-15 was shut-in. Following the loss of market, Well 43-09 was the only producer from 1966 through the 1980s. The OGWC remained largely unmoved, but a water saturation gradient developed (as seen in Figure 19) as Well 43-09 took cumulative recovery to just over 2 BCF. This result from the model corroborates anecdotal evidence from operators as noted in the well history files. The gradient at this time had moved to 5,031 feet, or approximately 10 feet above the OGWC.

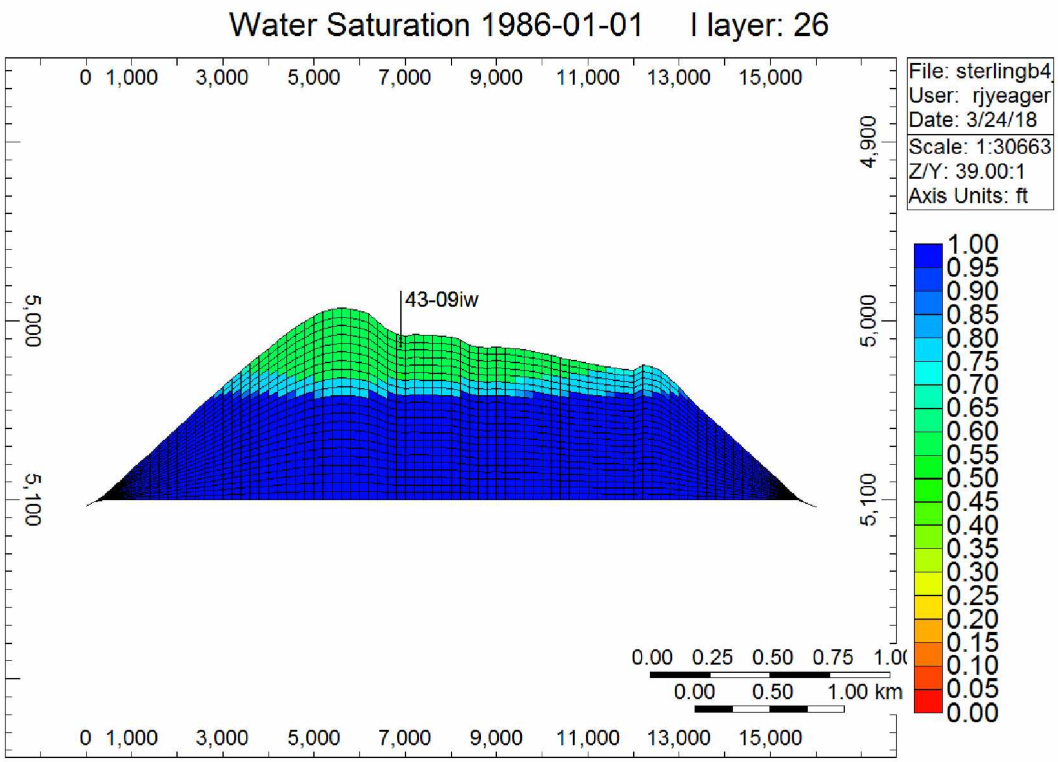

Figure 19. Well 43-09 shown at end of its production life.

Water influx began with initial production, but substantially increased with 43-09 production. The cumulative influx volume as seen in Figure 20 shows the encroaching water drove the reservoir pressure higher and closer to initial pressure.

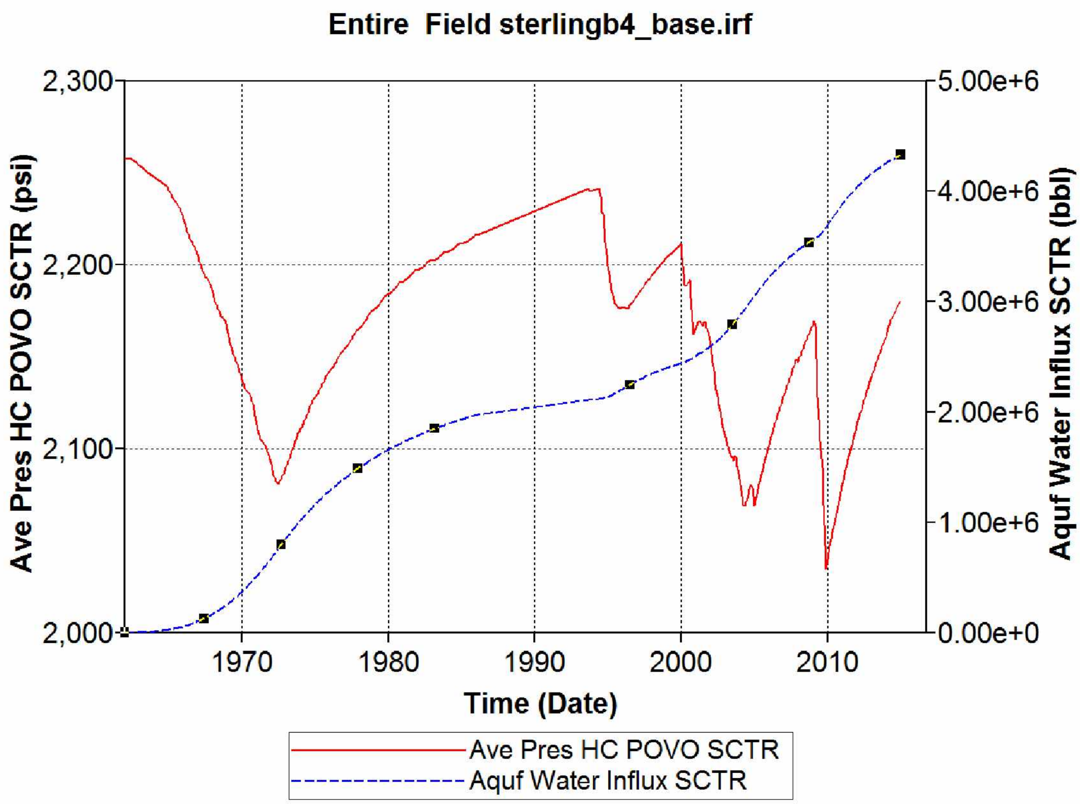

Figure 20. Reservoir model pressure history with cumulative water influx.

As observed, the reservoir pressure approaches the initial pressure as the water influx continues. This drives the water contact upward. Gas production was ceased from 1986 to 1998, so well activity was not contributing to water movement. Well 32-09 begins gas production in 2000 and the contact top has moved from 5,301 to 5,027 feet.

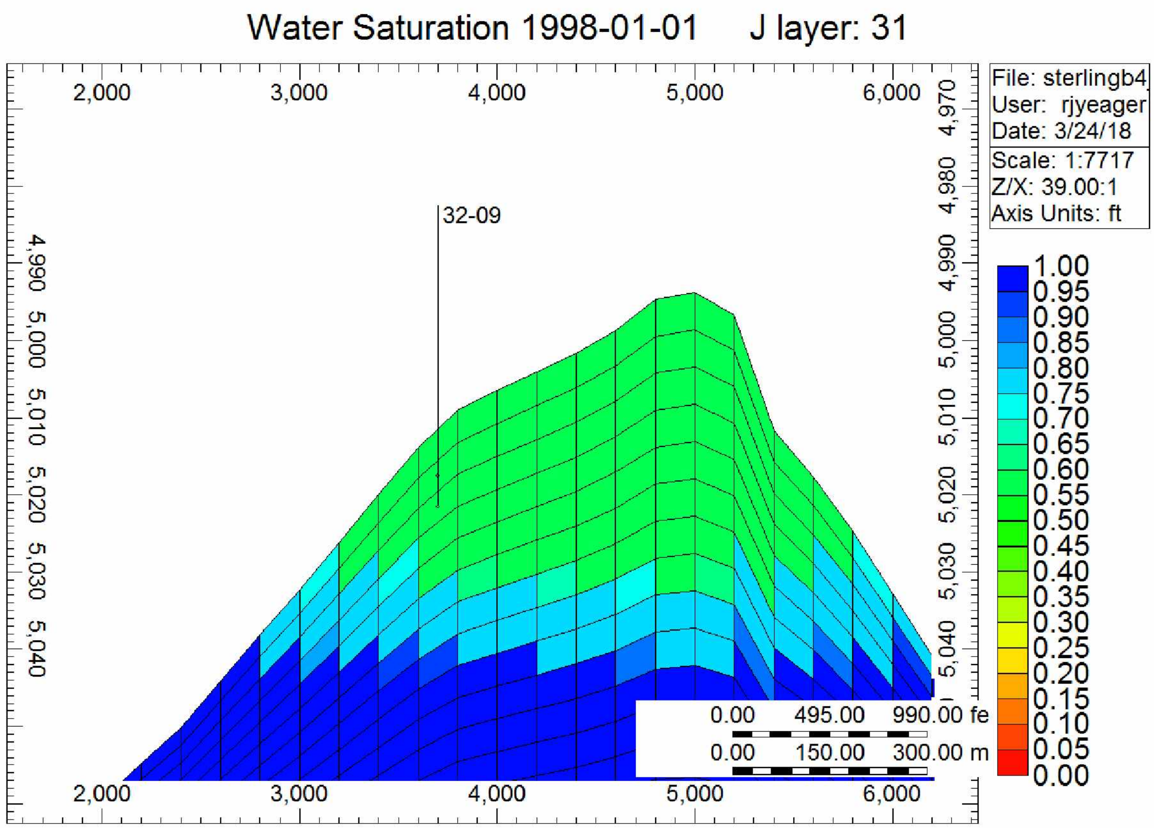

Figure 21. Well 32-09 shown before production begins.

Once Well 32-09 production began, water moved strongly upward and the well watered out. The contact migrated upward to 5,022 feet by early 2006, the time of shut-in, as seen in Figure 22, with the associated gas and water production rates in Figure 23.

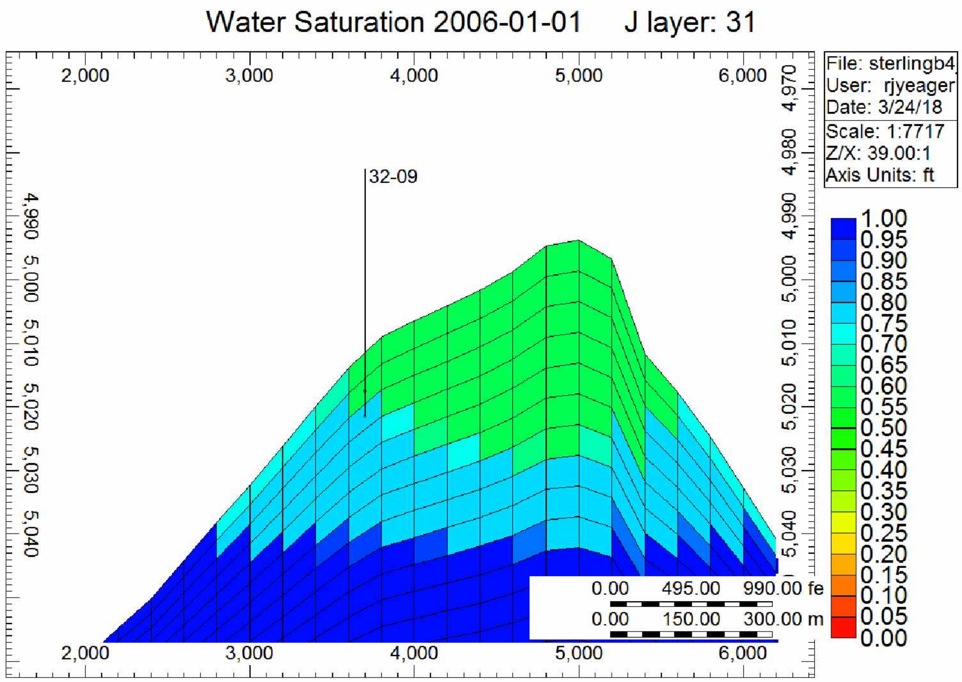

Figure 22. Well 32-09 shown after production ends and a water coning effect is seen around the wellbore.

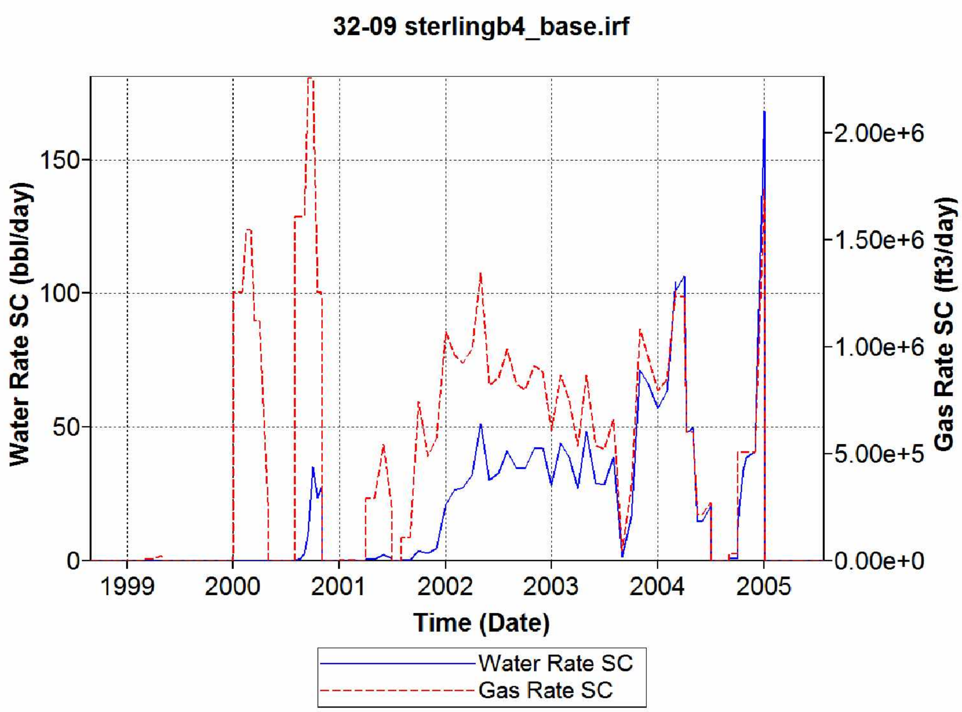

Figure 23. Water and gas production rates for Well 32-09.

It was at this time that water injection began in Well 43-09 and contributed to the gradient, as seen in Figure 24.

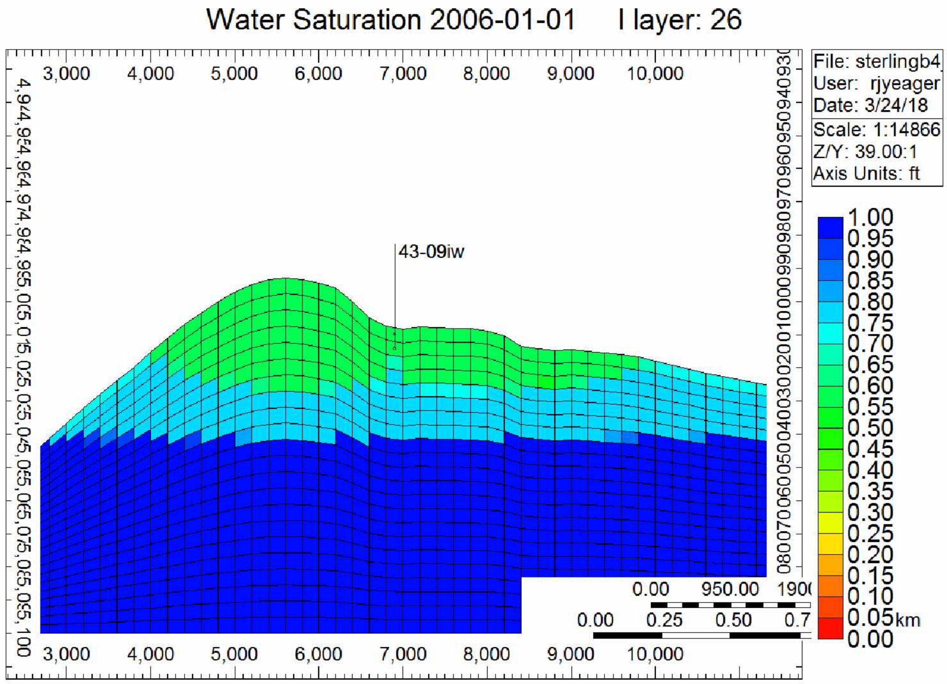

Figure 24. Well 43-09 shown after water injection begins.

Well 43-9X was being planned at this point in time to implement co-production. The saturation before the well begins production is seen in Figure 25.

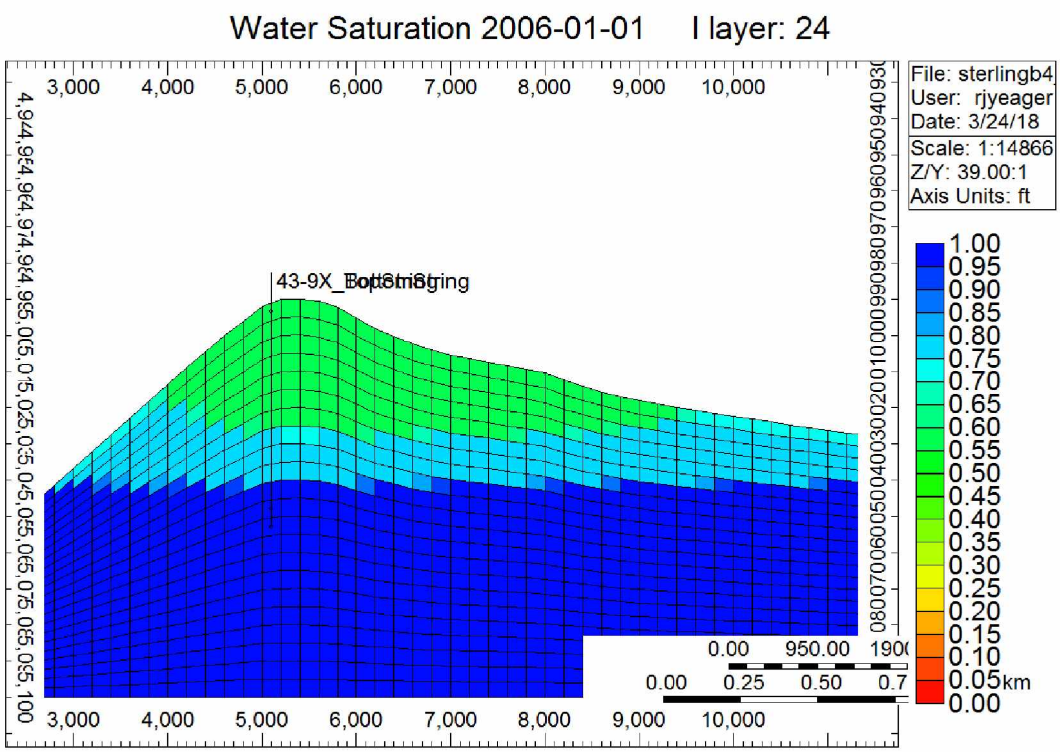

Figure 25. Well 43-9X shown before production begins.

As co-production begins, a reverse water cone is developed around the wellbore. However, the contact continues the upward migration around the formation's edges. Despite the packer failing to completely isolate the two fluid streams and kill gas production, the co-production concept is shown to be successful in locally controlling the contact and reducing the water saturation as seen in Figure 26.

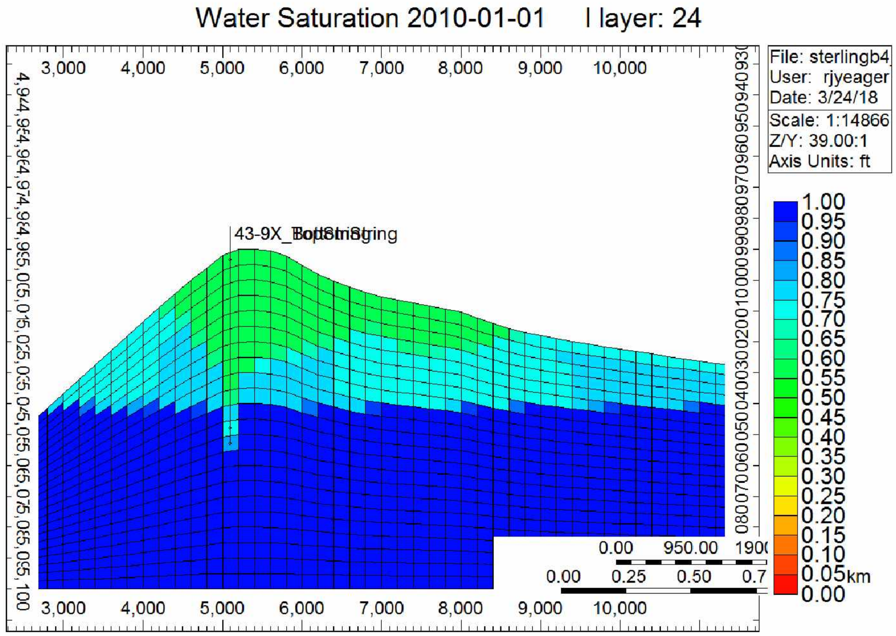

Figure 26. Well 43-9X shown after production ends and a reverse water cone effect is seen around the wellbore.

If Well 43-9X is viewed in the Z/X plane at the same timestep, the effect is amplified due to the geometry of the reservoir as seen in Figure 27.

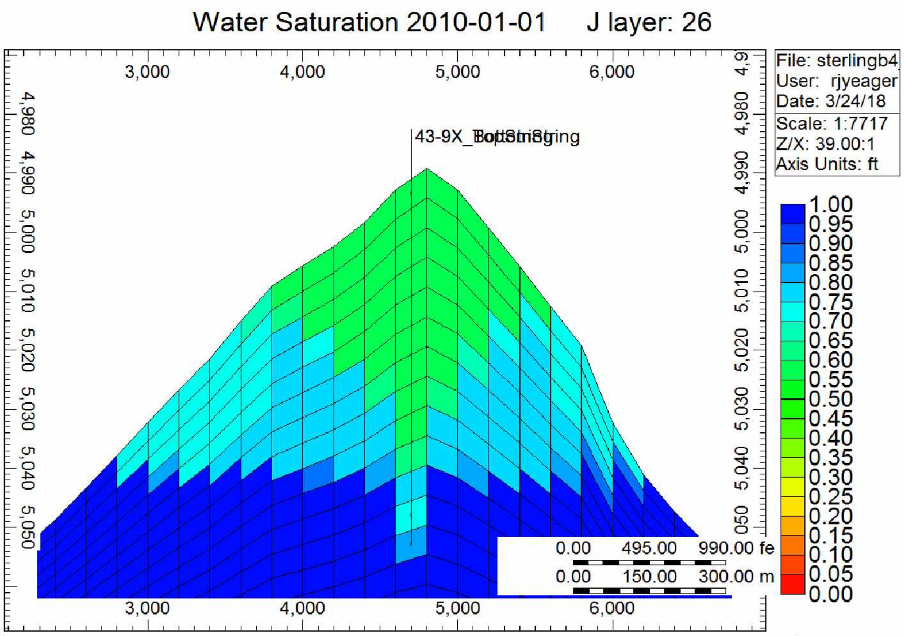

Figure 27. Enlarged and rotated view of Well 43-9X after production ends and a reverse water cone effect is seen around the wellbore.

Since 2000, the average water influx rate was approximatley 400 bbls/d. If co-production is going to be successfully implemented, the lower completion must produce water at this critical rate to maintain the GWC. To lower the contact and free gas for production, the water production rate must be in excess of the critical rate of 400 bbls/d. Well 43-9X only briefly produced above the critical rate as seen in Figure 28.

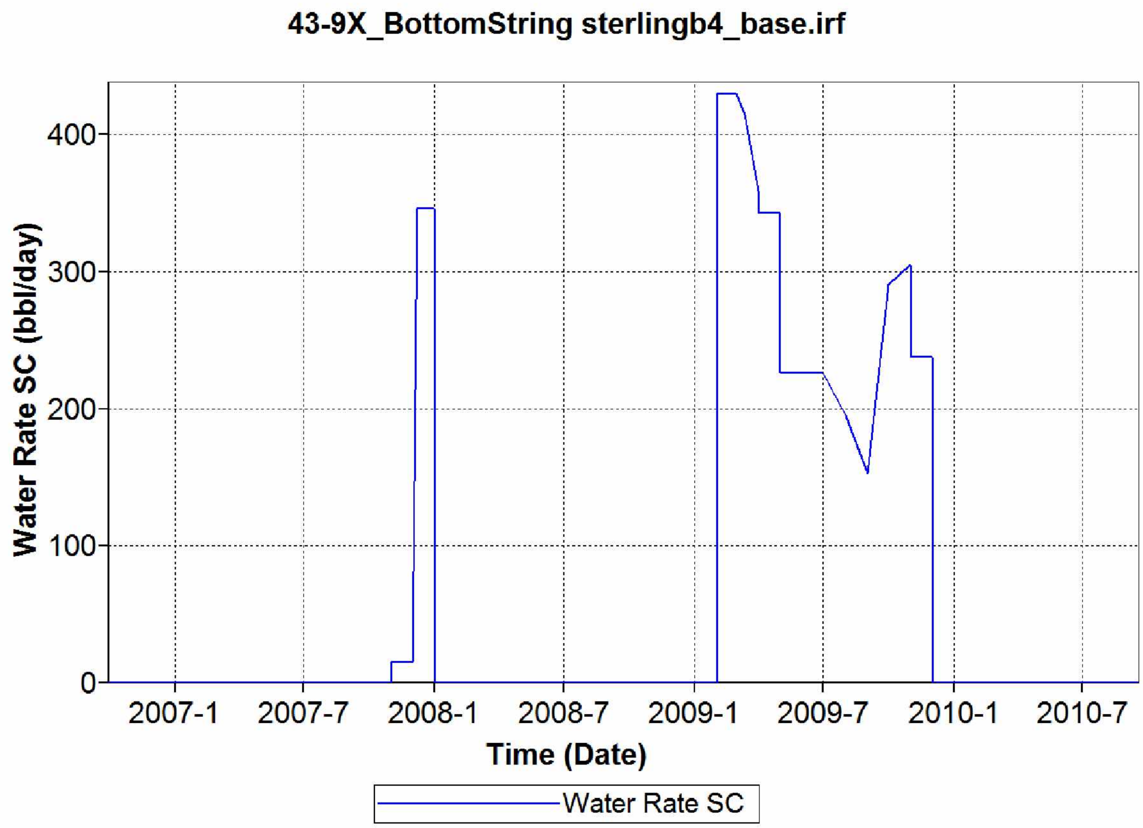

Figure 28. Well 43-9X water production from lower string.

Thus, a reverse cone was locally developed, but did not influence the contact globally. The contact sweeps upward as it leaves the proximity of the wellbore. Subsequent attempts to implement dual production in 2013 failed and 43-9X was shut-in. No further production from the Sterling B4 sands was attempted. The water saturation at the start of all prediction runs is shown in Figure 29, with the top of the contact located at a depth of 5,015 ft SSTVD.

The model has shown that a movement of six feet has been effected from initial conditions to present conditions. This movement is supported by the type logs of wells run at different points in time also demonstrating an upward movement of six feet over 50 years. This corresponds to a production of 3.8 BCF. If the six feet of volume previous occupied by gas is assumed to be 100% swept as the water moves upward then the corresponding volume is 3.8 MCF. Though typical sweep efficiency is far less than 100%. A residual gas saturation of 25-30% should be expected in a gas like this.

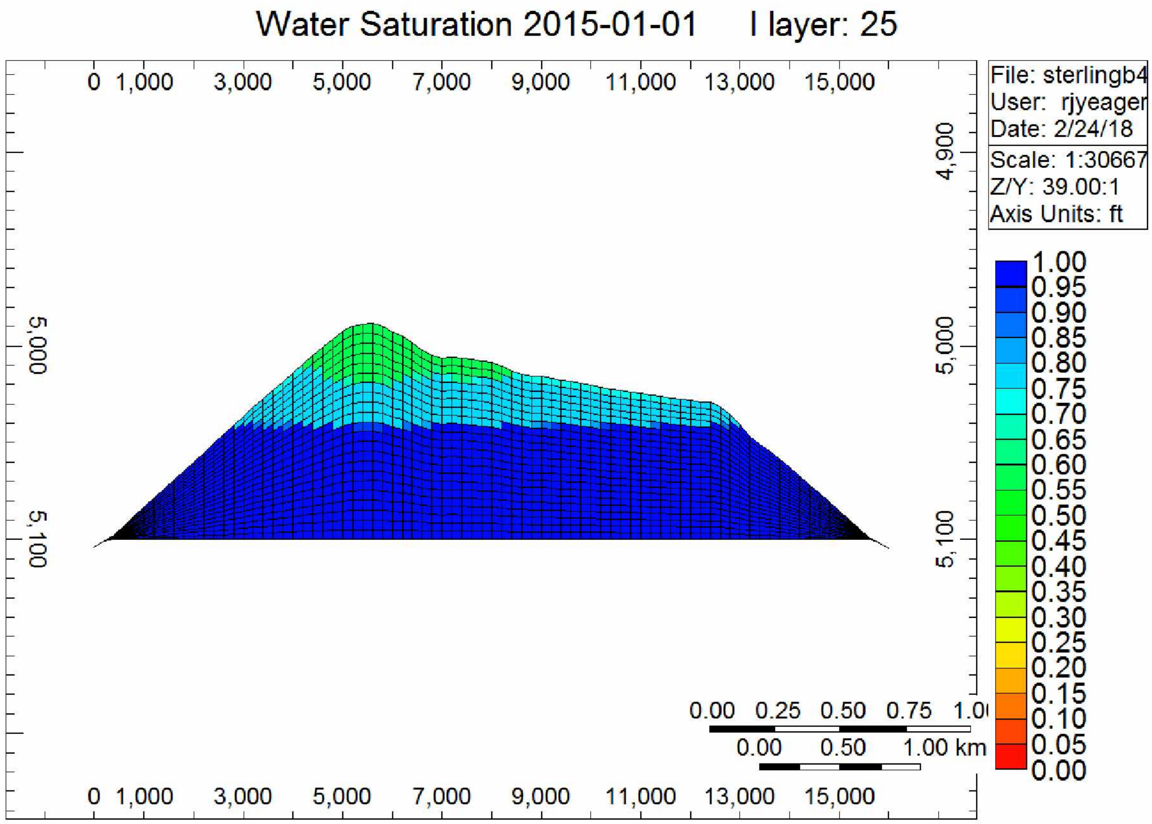

Figure 29. Water saturation overview at beginning of all prediction cases.

The first objective of this study is to demonstrate that the reservoir has the capability to deliver an additional benefit of at least 1 BCF. A volumetric estimate of the reservoir, from the top of the formation to the top of the contact, was developed to determine whether this objective was met. This estimate was developed in the same manner as that in Section 2.4, and is captured in Table 4.

Step	Contour	Area	Average Area	Height	Volume
	(ft)	(ft^2)	(ft^2)	(ft)	(ft^3)
1	4990	237,209	847,335	10	8,473,350
	5000	1,457,461			
2	5000	1,457,461	3,338,069	10	33,380,685
	5010	5,218,676			
3	5010	5,218,676	7,591,230	10	75,912,296
	5018	9,963,783			

Table 4. Gross volume information above the gas-water contact.

The sum of the volumes is 117,766,331 ft^3. This volume is then used to determine remaining gas-in-place above the gas-water contact. The compressibility factor at present conditions is 0.88, the current reservoir pressure is 1,973 psi, and the temperature is assumed to be the same at 103F, or 562.7 Rankine. The formation volume factor is thus determined:

$$B_{gi} = 0.0282793 \frac{0.88(562.7)}{1{,}973\, psi} rcf/scf = 0.007097\, rcf/scf$$

And the remaining gas-in-place:

$$G = \frac{117{,}766{,}331 ft^3 (0.26)(1.0 - 0.4)}{0.007097 \frac{rcf}{scf}} = 2{,}588{,}636\, mscf$$

Therefore, almost 2.6 BCF of gas remains above the gas-water contact. If 40% of remaining gas above the contact is assumed to be recoverable, then 1.04 BCF is the incremental benefit. This is greater than the minimum 1 BCF objective: the objective is achieved. The reservoir presents itself as an attractive target.

5.2 Production Results

The second objective of the project is to determine which production strategies, out of those previously identified, are technically capable of producing the incremental benefit of 1 BCF of gas. Table 5 captures the recovery of each case. Where noted, “lower gas recovery” indicates gas recovery with water from the lower completion, bringing “lower gas” to sales would require additional equipment to separate the streams and recompress the gas to sales pressures, in addition to water disposal costs.

Production Type	Gas Rate	H2O rate	Cumulative Gas Recovery		Cum H2O
			Upper	Lower	
	mscf/d	bbl/d	mscf	mscf	bbls
Co-Production: New Horizontals	200		1,513,380	N/A	7,566,900
	400		1,546,000	N/A	3,865,000
	600		1,442,400	N/A	2,404,000
	800		1,313,600	N/A	1,642,000
	1000		1,186,000	N/A	1,186,000
Co-Production: New Vertical	200		239,017	594,349	427,955
	400		370,232	467,826	344,552
	600		475,611	371,538	308,832
	800		562,486	292,878	269,168
	1000		629,583	232,376	241,024
Co-Production: New Lower Horizontal with 43-9X Upper	200	500	839,600	N/A	2,099,500
	200	1,000	1,460,800	N/A	7,305,000
	200	1,500	1,460,800	N/A	10,957,500
	400	500	803,000	N/A	1,004,000
	400	1,000	1,436,600	N/A	3,592,000
	400	1,500	2,229,145	N/A	10,134,000
	600	500	766,000	N/A	638,500
	600	1,000	1,259,800	N/A	2,100,000
	600	1,500	2,276,135	N/A	8,127,000
	800	500	729,400	N/A	456,000
	800	1,000	1,343,655	N/A	2,070,000
	800	1,500	2,230,999	N/A	6,984,000
	1000	500	46	N/A	23,000
	1000	1,000	1,274,383	N/A	1,734,000
	1000	1,500	2,164,127	N/A	6,483,000
Infill Drilling: New Horizontal	200		715,300	N/A	N/A
	400		733,660	N/A	N/A
	600		743,550	N/A	N/A
	800		754,400	N/A	N/A
	1000		762,000	N/A	N/A
Infill Drilling: New Vertical	200		712,200	N/A	N/A
	400		730,400	N/A	N/A
	600		738,900	N/A	N/A
	800		742,000	N/A	N/A
	1000		731,000	N/A	N/A
Variable Production: Only Upper String	200		732,027	N/A	N/A
	400		719,827	N/A	N/A
	600		707,627	N/A	N/A
	800		706,627	N/A	N/A
	1000		688,627	N/A	N/A

Table 5. Production results overview.

The production schemes are plotted in Figure 30.

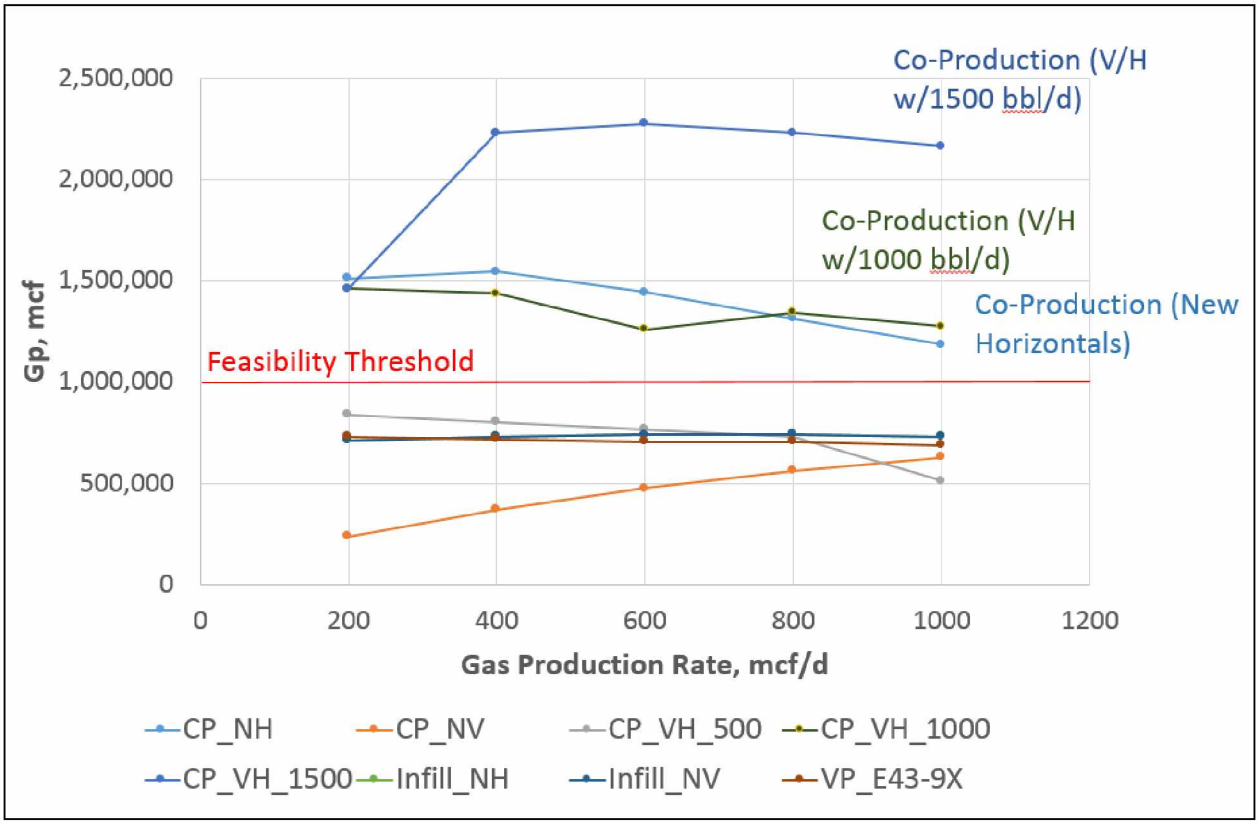

Figure 30. All production schemes plotted against the feasibility threshold.

The vertical co-production may be somewhat limited due to the geometry of the reservoir. The vertical wellbore allows a localized coning effect to take place, but does not map well against the overall structure. More importantly, though, the lower perforation was unable to maintain a water production in excess of the noted critical rate despite a FBHP of near zero as seen in Figure 31 which is from the 1,000 mcf/d case.

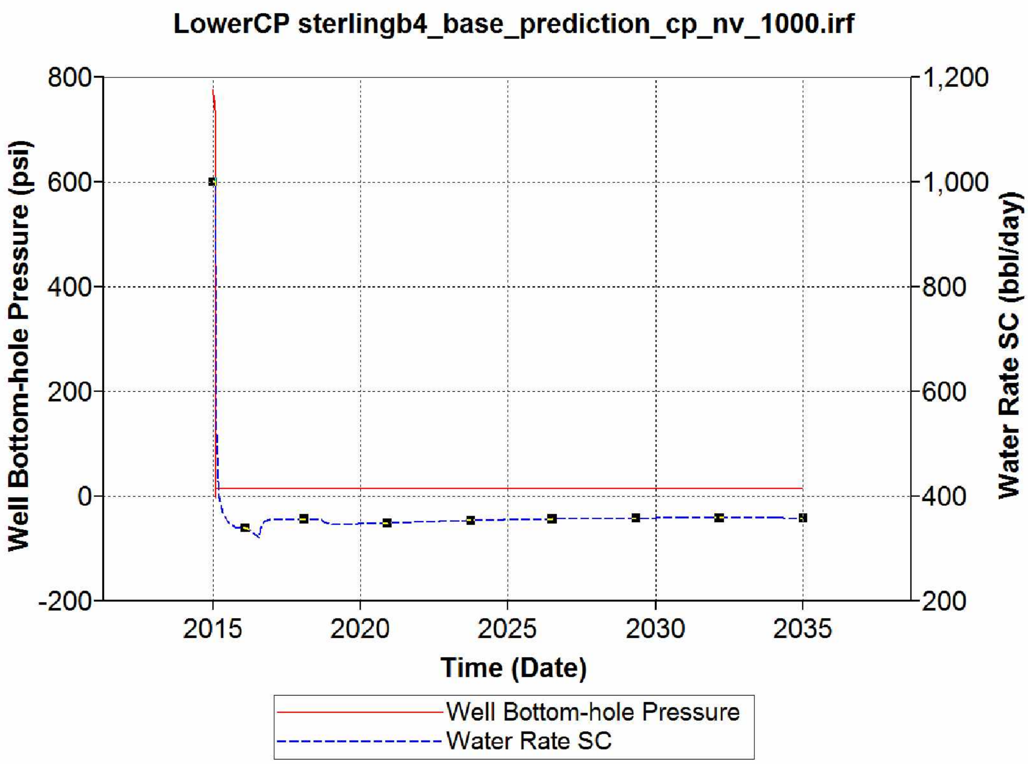

Figure 31. Water production from lower well against well bottom-hole pressure.

Infill drilling, whether horizontal or vertical, is limited to less than 1 BCF and does not meet the objective of this project. This option utilizes primary recovery means and provides no attempt to control, manage or avoid the gas-water contact. Therefore, this option is not considered technically feasible.

The last option considers the existing gravel packer in Well 43-9X to be replaced (thereby fully isolating the top and bottom perforations) and then producing gas from the upper perforation with primary recovery means. No production from the lower perforation would be attempted. This option, like infill drilling, does not meet the objective of the project and is not considered to be technically feasible.

Co-production methods utilizing lower horizontal wells for contact control are the only cases that resulted in cumulative recovery above the minimum required 1 BCF. A horizontal well allows a wellbore path that more effectively follows the structural shape and would be favored for a global effect. Further, relatively low placement in the water zone allows the water production rate to be above the critical rate necessary for contact control.

The dual horizontal configuration was able to adequately control the contact, so long as the pressure difference between the upper and lower wells was maintained above a specific limitation. The 200 mcf/d rate ran to past end of the simulated 20 years without watering-out (nearly 21 years), while the 1000 mcf/d rate terminated within a few years. The water production rate on the lower horizontal was 1,000 bbl/d in all cases. The gas and water production rates for the five cases considered with the associated BHP deltas between the two wells are shown in Figures 32 through 41.

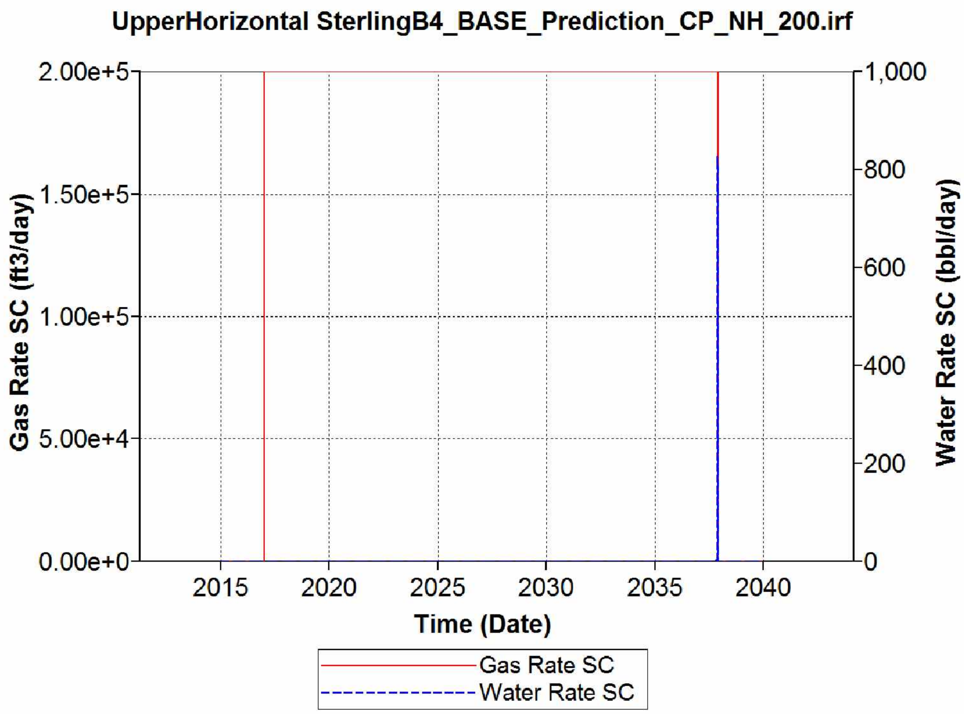

Figure 32. Gas and water production rates for upper hor. well producing at 200 mcf/d.

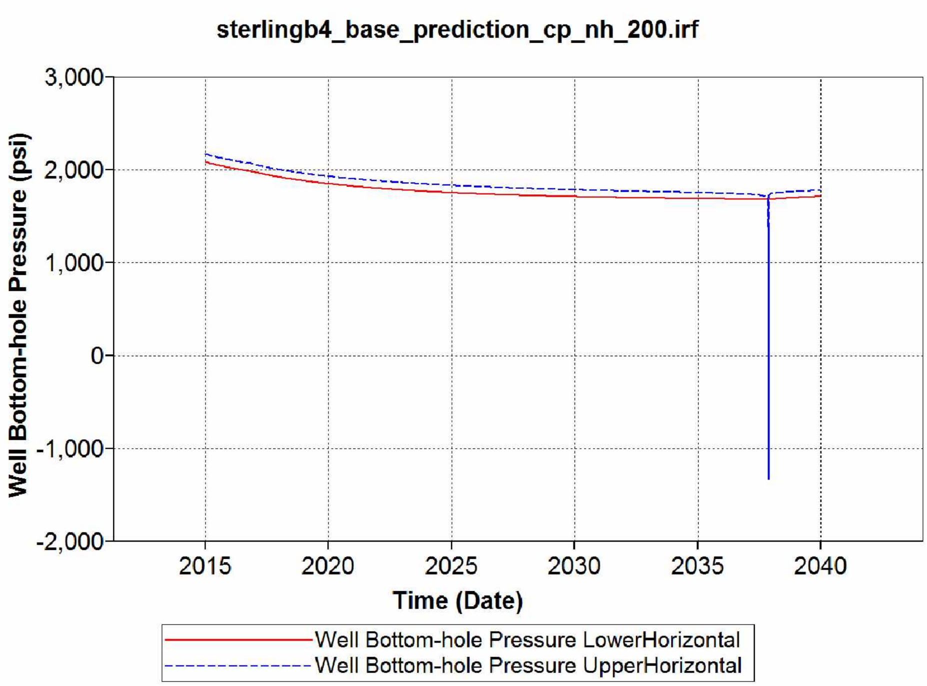

Figure 33. Pressure difference between upper and lower hor. wells for gas production rate of 200 mcf/d.

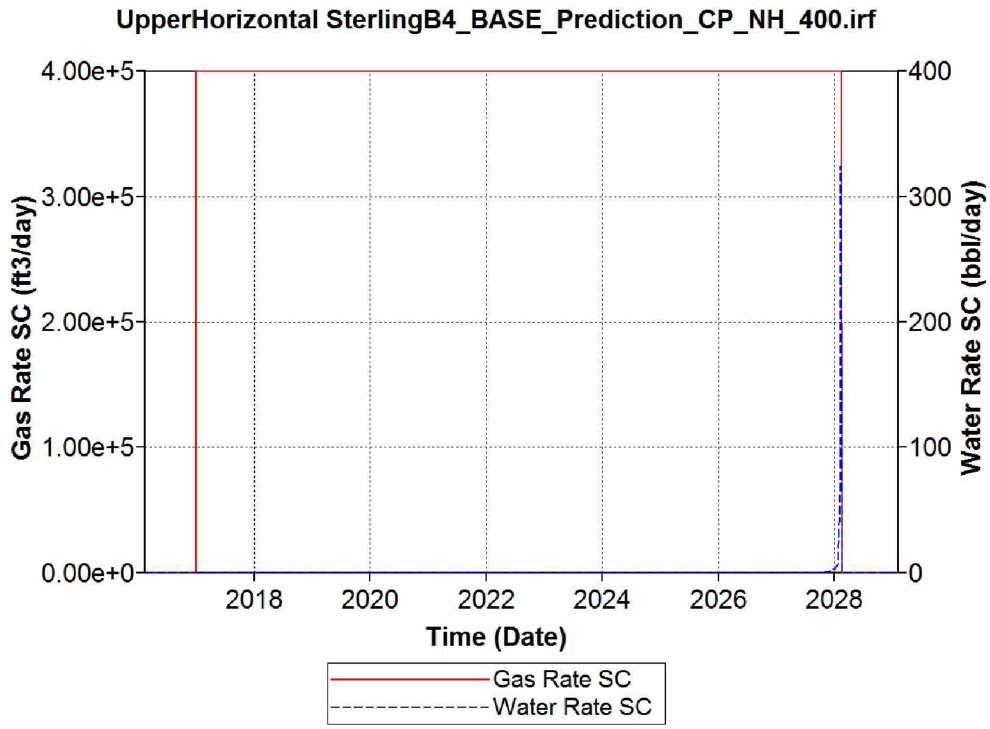

Figure 34. Gas and water production rates for upper horizontal well producing at 400 mcf/d.

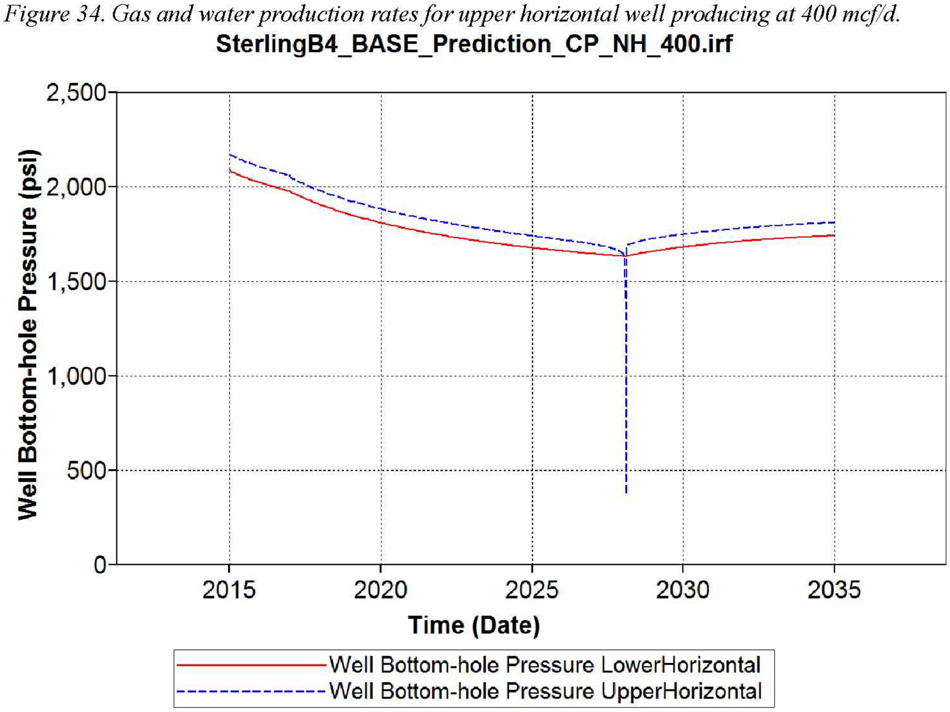

Figure 35. Pressure difference between upper and lower horizontal wells for gas production rate of 400 mcf/d.

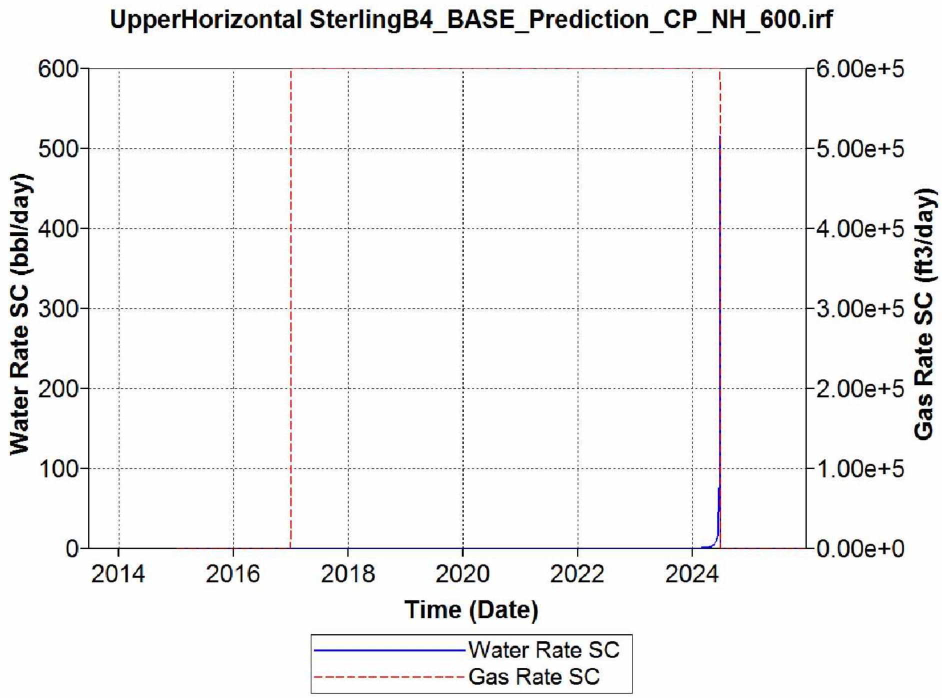

Figure 36. Gas and water production rates for upper horizontal well producing at 600 mcf/d.

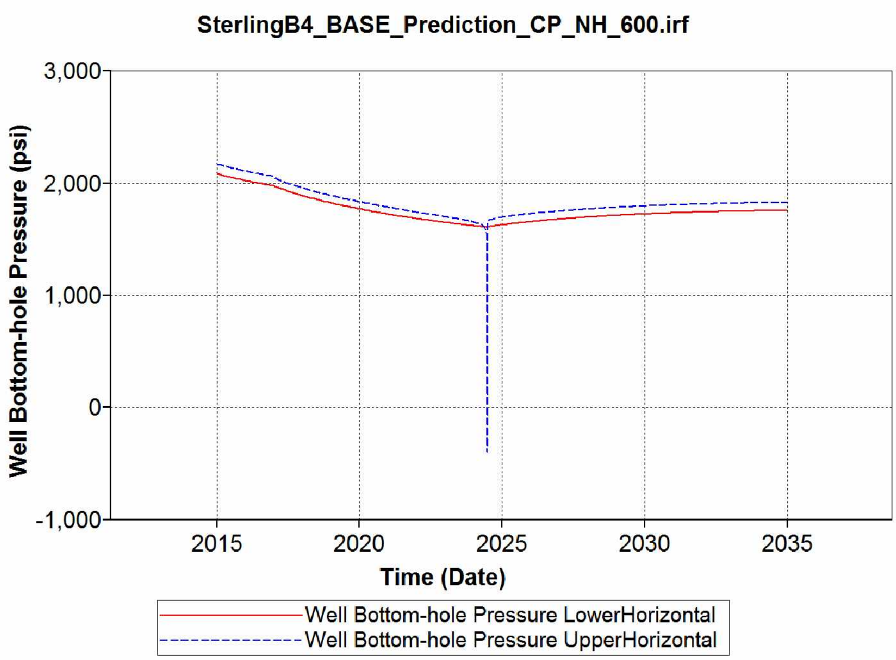

Figure 37. Pressure difference between upper and lower horizontal wells for gas production rate of 600 mcf/d.

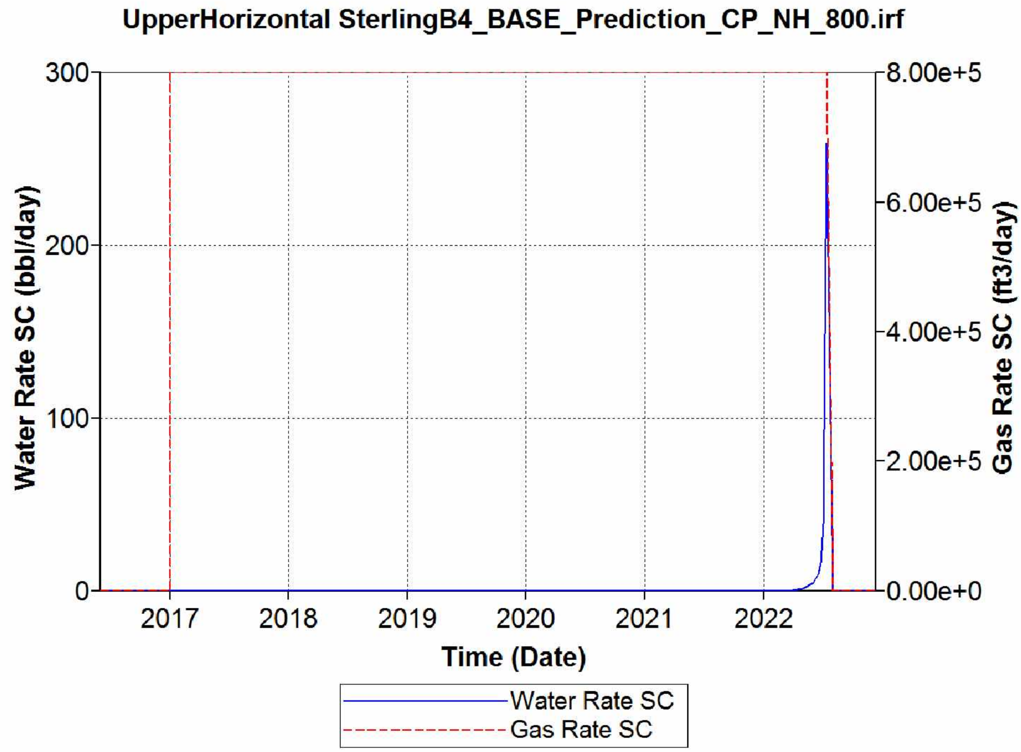

Figure 38. Gas and water production rates for upper horizontal well producing at 800 mcf/d.

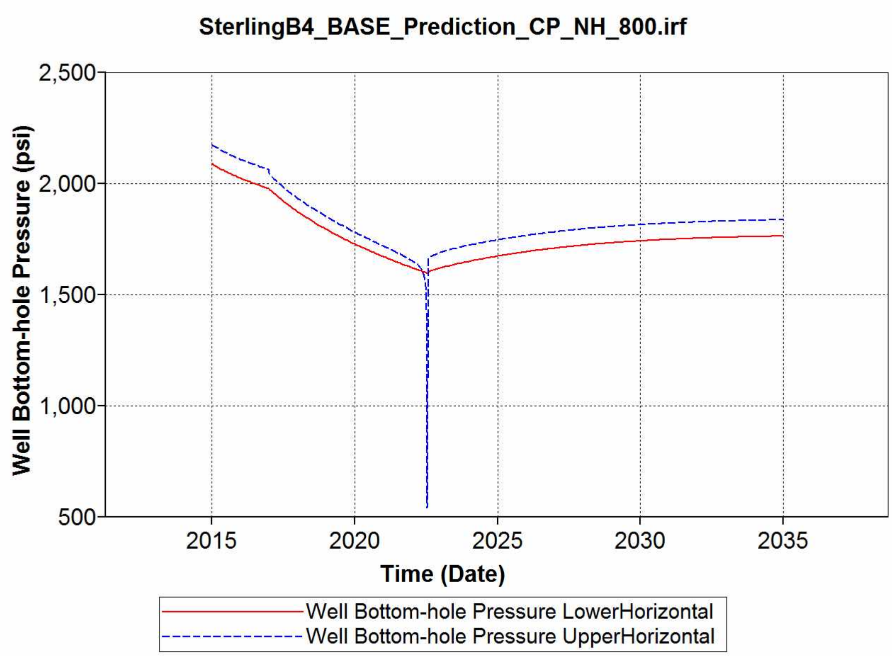

Figure 39. Pressure difference between upper and lower horizontal wells for gas production rate of 800 mcf/d.

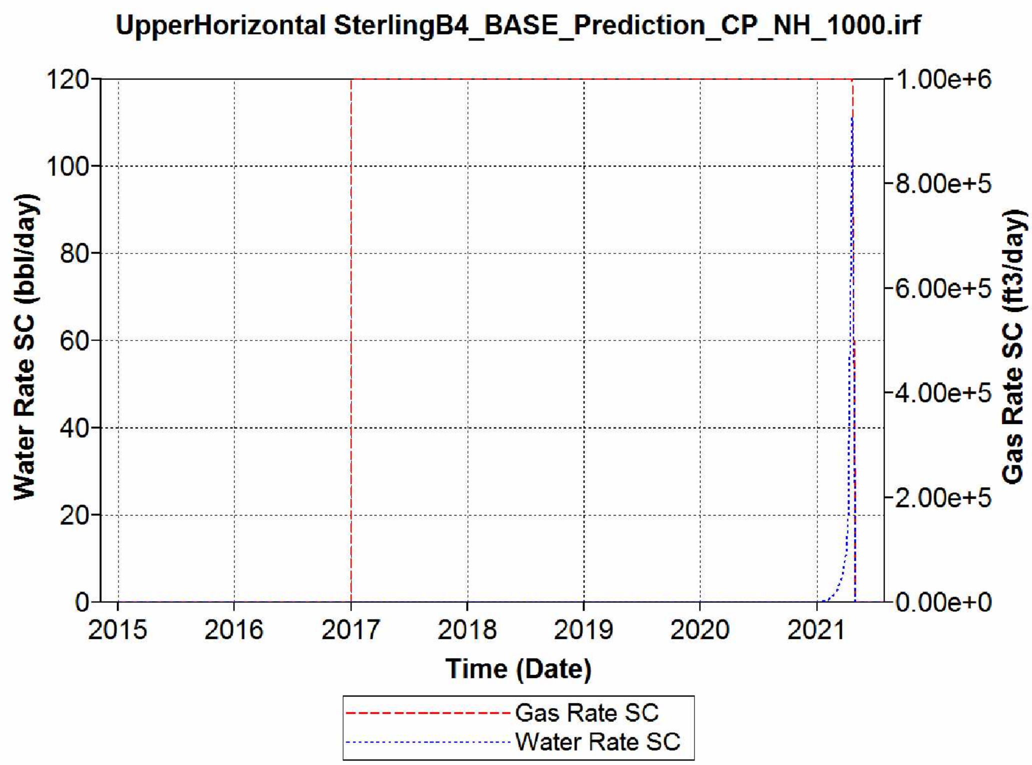

Figure 40. Gas and water production rates for upper horizontal well producing at 1,000 mcf/d.

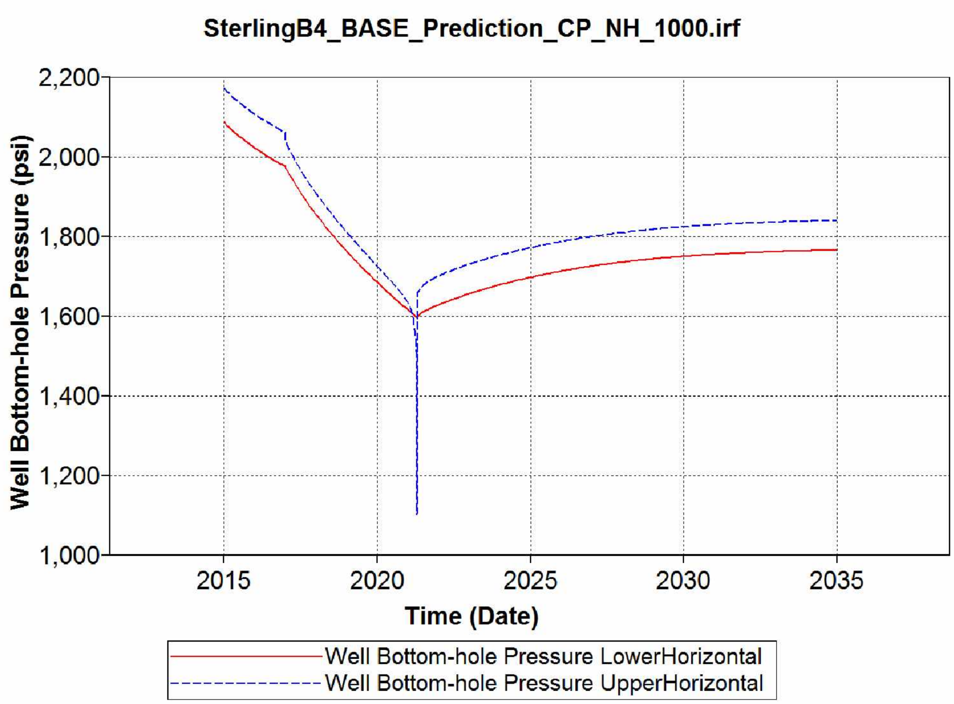

Figure 41. Pressure difference between upper and lower horizontal wells for gas production rate of 1,000 mcf/d.

These results are captured in Table 6, which demonstrates that wells are watered-out and subsequently shut-in when ΔP decreases. The shut-in ΔP slightly decreases as the gas production rate increases.

Gas Rate	Initial ΔP	Shut-in ΔP	Time to SI
mcf/d	psi	psi	mos
200	83.1	61.3	250
400	83.1	60.6	128
600	83.1	59.2	79
800	83.1	55.4	54
1000	83.1	51.8	39

Table 6. Pressure delta against time to shut-in.

This information indicates that a higher cumulative recovery may be possible if the gas production rate is stepped down as the ΔP nears the indicated shut-in limit. A production plan implementing this strategy was developed and produced gas at 1000 mcf/d until the ΔP decreased to the specified limit, 70 psi, then stepped down to 800 mcf/d and continued until ΔP of 70 psi again triggers a step-down in production rate. The plan delivered significantly less benefit than a stable gas production rate but significantly extended the production life. After significant production, an upward sweep of water as experienced with the stable production rate allows for pressure maintenance in the gas zone and this stepped-down method relies only on primary recovery.

The vertical-horizontal co-production method (utilizing an existing upper vertical completion with a new lower horizontal well) achieves similar and even greater cumulative recovery than the dual-horizontal co-production configuration, so long as the water production rate is held at or above 1,000 bbl/d. The water rate was modified for this option and saw increased recovery with greater water production. The greater the ΔP, the higher the incremental recovery. A rate of 500 bbl/d water was determined to not be sufficiently greater than the critical rate to materially affect incremental recovery, but it did control the gas-water contact. See cumulative gas production in Figures 42 through 54 for the 500, 1,000, and 1,500 bbl/d water production rates, respectively.

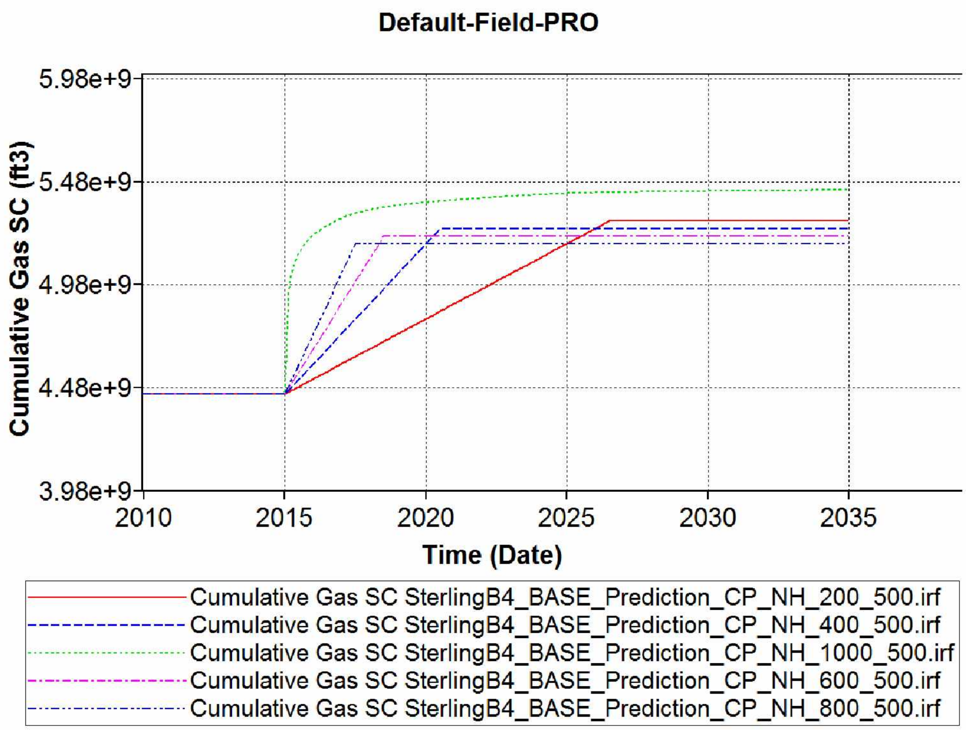

Figure 42. Cumulative gas with lower horizontal water production rate of 500 bbl/d.

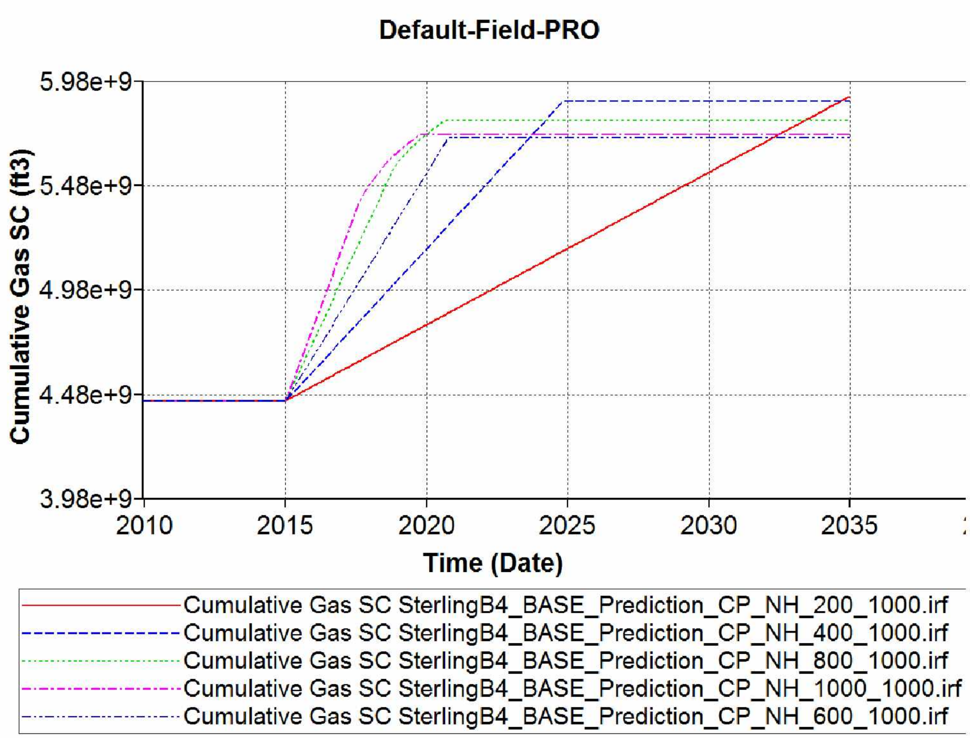

Figure 43. Cumulative gas with lower horizontal water production rate of 1,000 bbl/d.

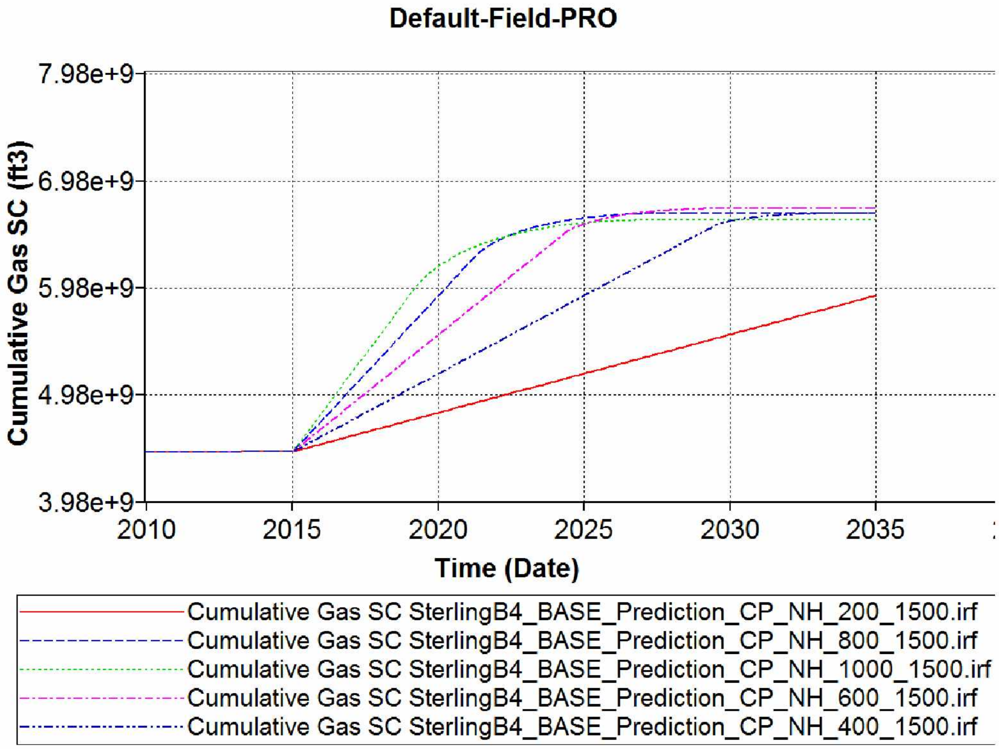

Figure 44. Cumulative gas with lower horizontal water production rate of 1,500 bbl/d.

Similar to the other co-production method, the gas and water production rates and BHP between the two wells for the five cases with water production held at 1,000 bbl/d is shown below in Figures 44 through 53.

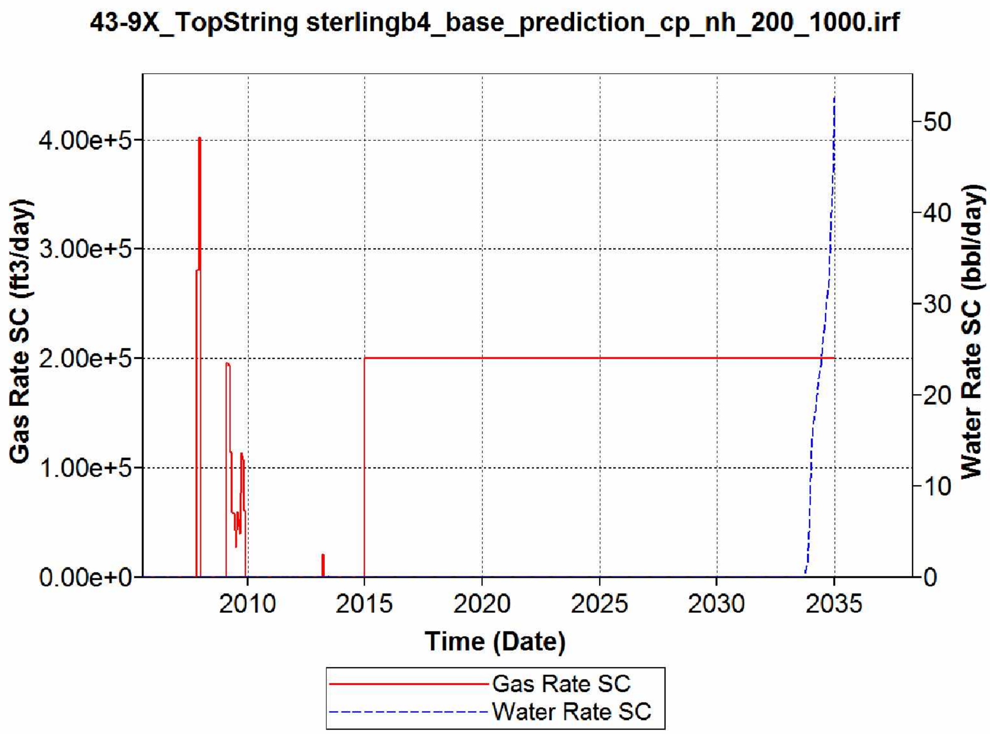

Figure 45. Gas and water production rates for upper existing 43-9X producing gas at 200 mcf/d.

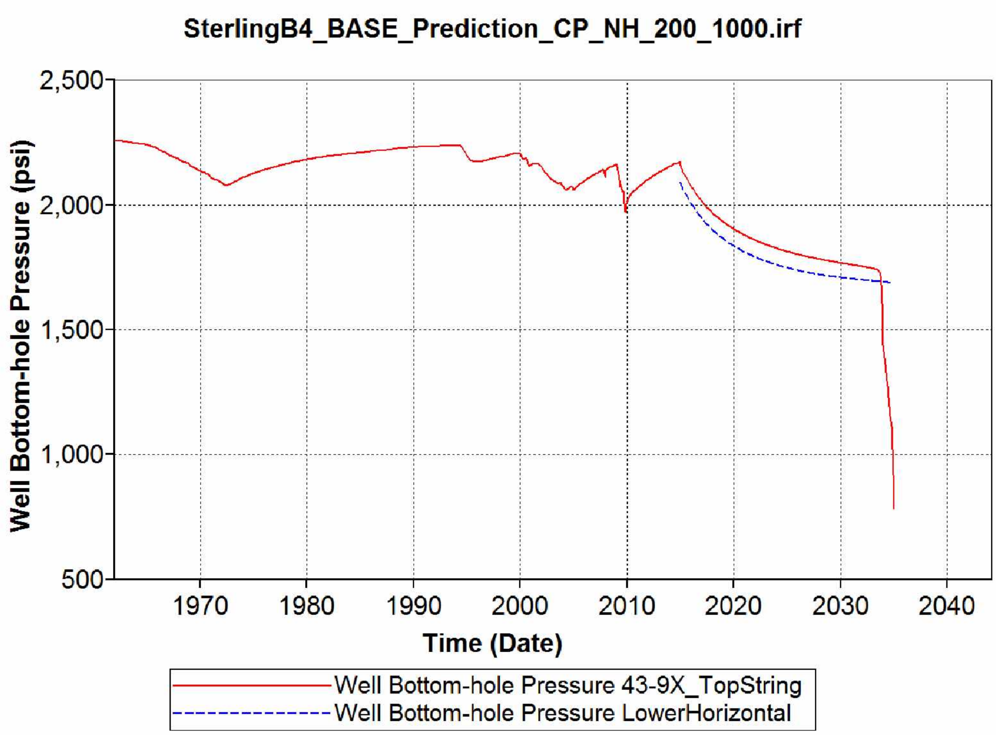

Figure 46. Pressure difference between upper vertical well and lower horizontal wells for gas production rate of 200 mcf/d and water production rate of 1,000 bbls/d.

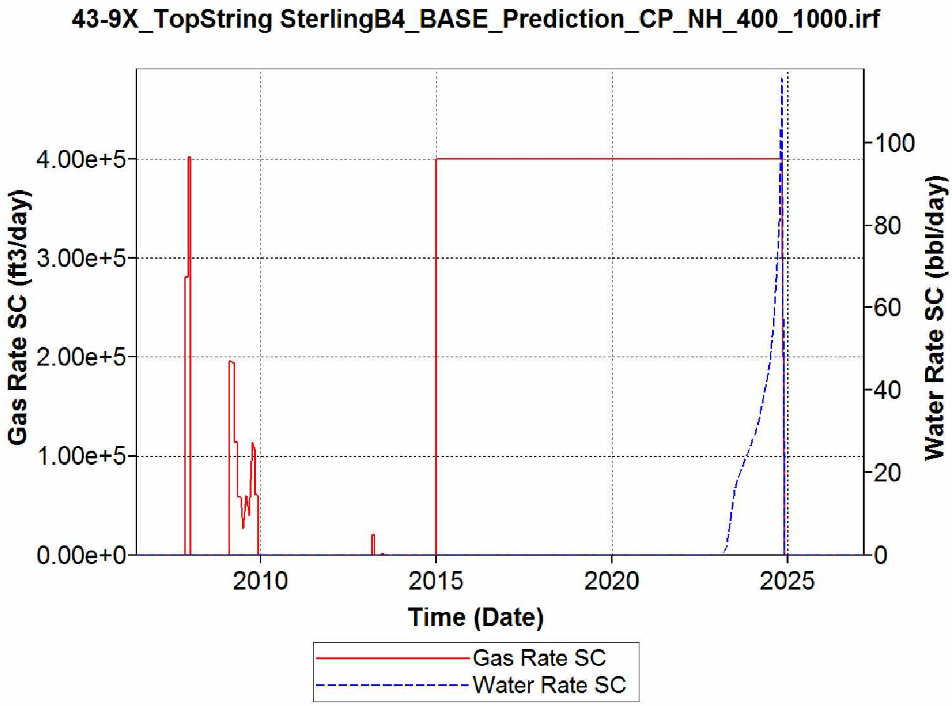

Figure 47. Gas and water production rates for upper existing 43-9X producing gas at 400 mcf/d.

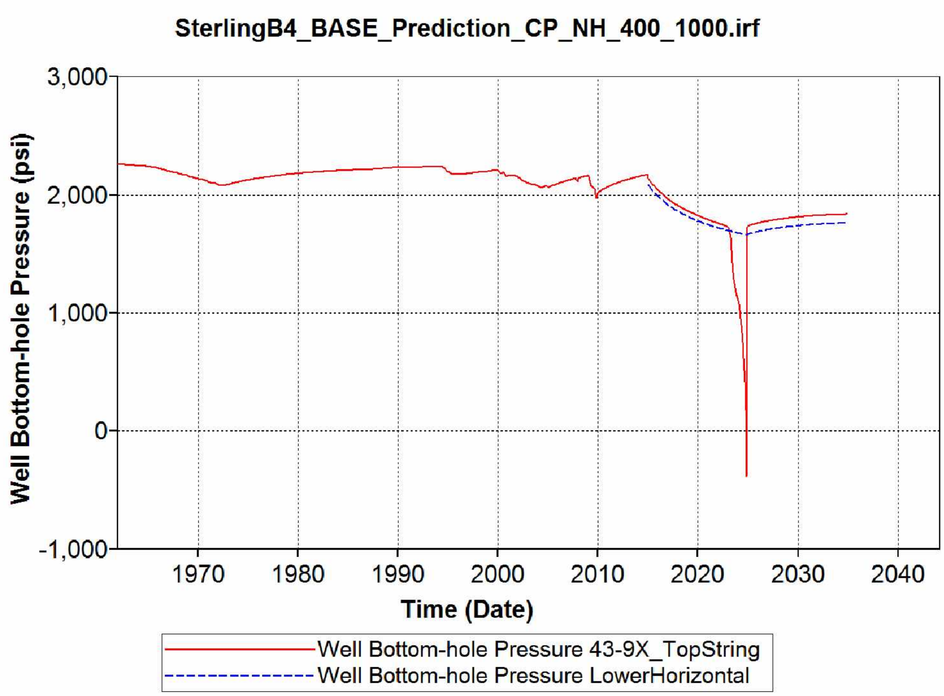

Figure 48. Pressure difference between upper vertical well and lower horizontal wells for gas production rate of 400 mcf/d and water production rate of 1,000 bbls/d.

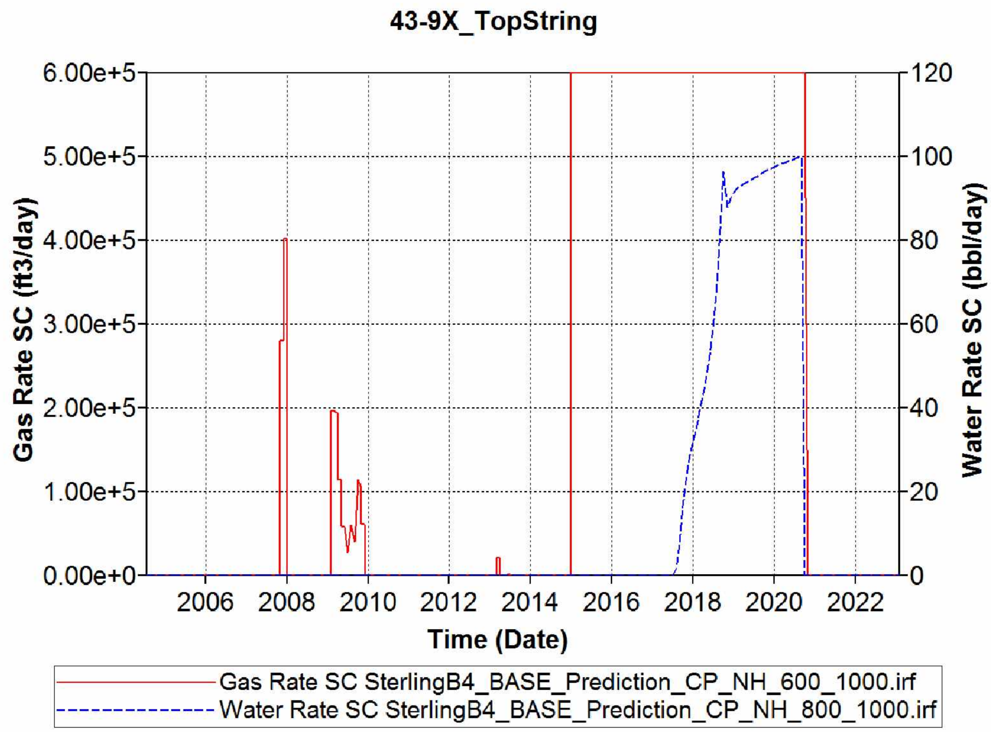

Figure 49. Gas and water production rates for upper existing 43-9X producing gas at 600 mcf/d.

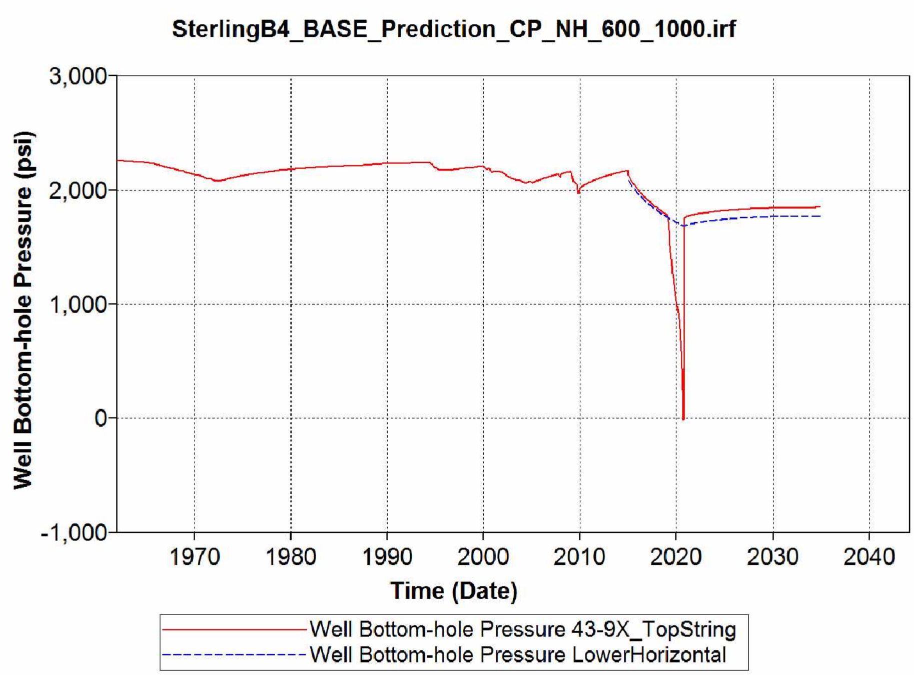

Figure 50. Pressure difference between upper vertical well and lower horizontal wells for gas production rate of 600 mcf/d and water production rate of 1,000 bbls/d.

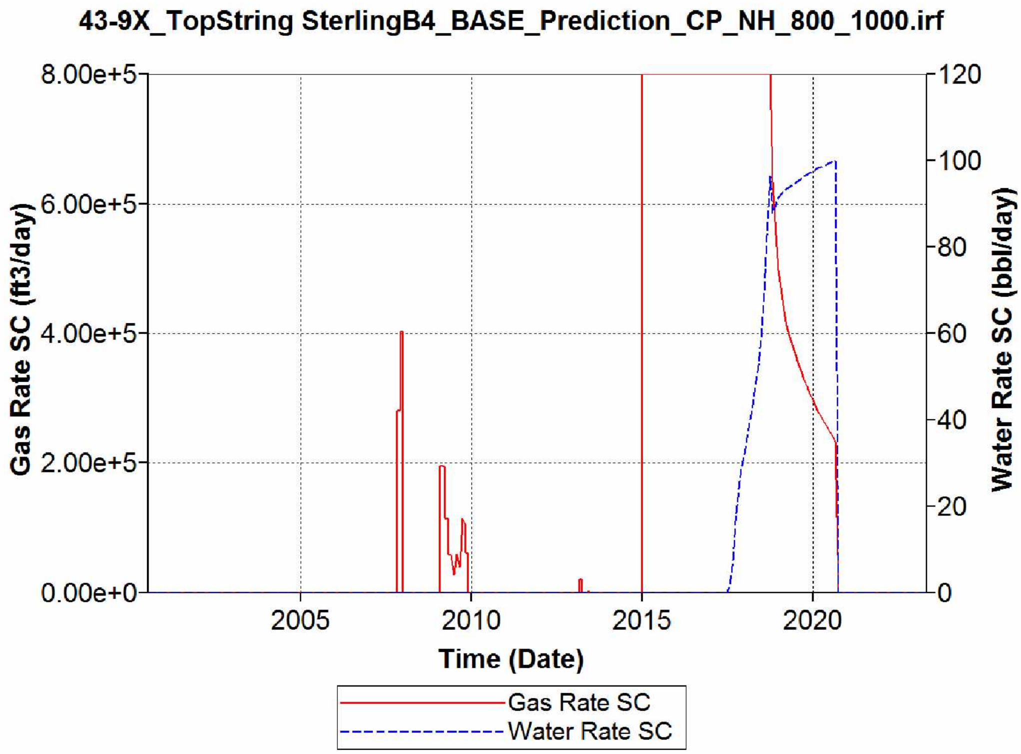

Figure 51. Gas and water production rates for upper existing 43-9X producing gas at 800 mcf/d.

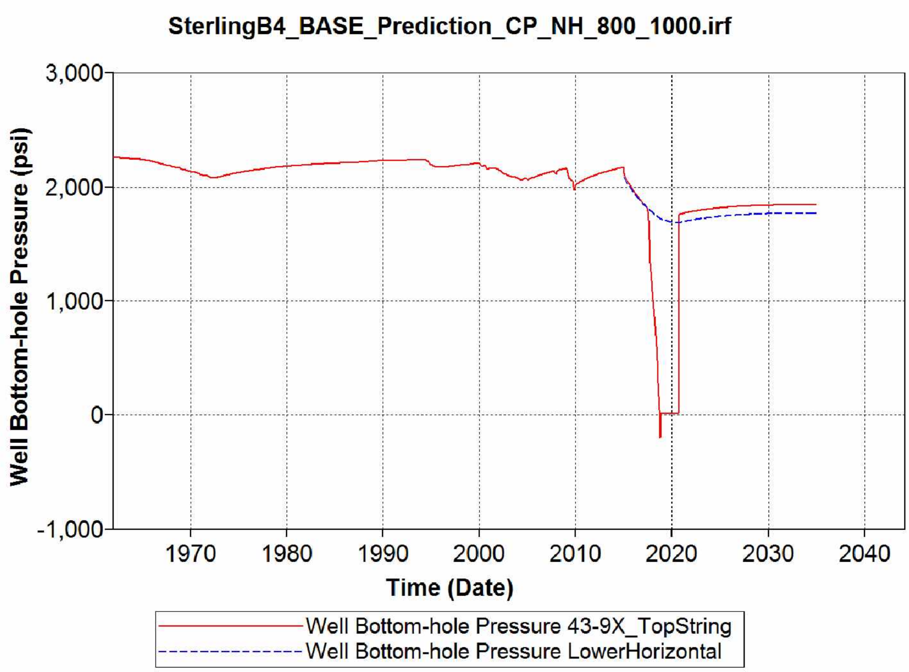

Figure 52. Pressure difference between upper vertical well and lower horizontal wells for gas production rate of 800 mcf/d and water production rate of 1,000 bbls/d.

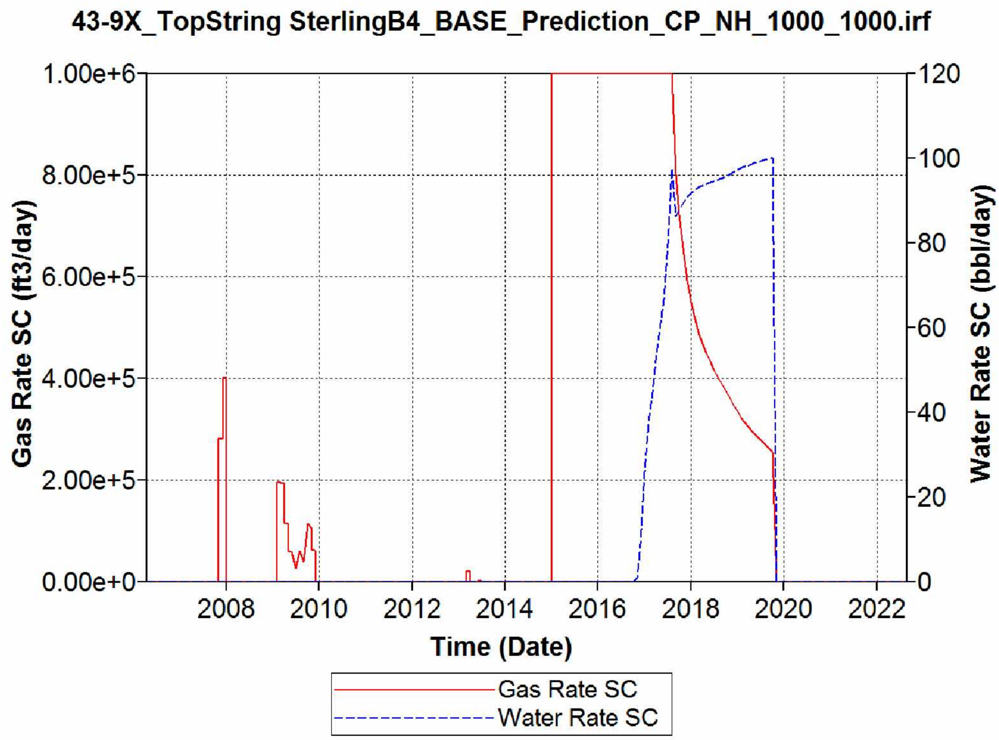

Figure 53. Gas and water production rates for upper existing 43-9X producing gas at 1,000 mcf/d.

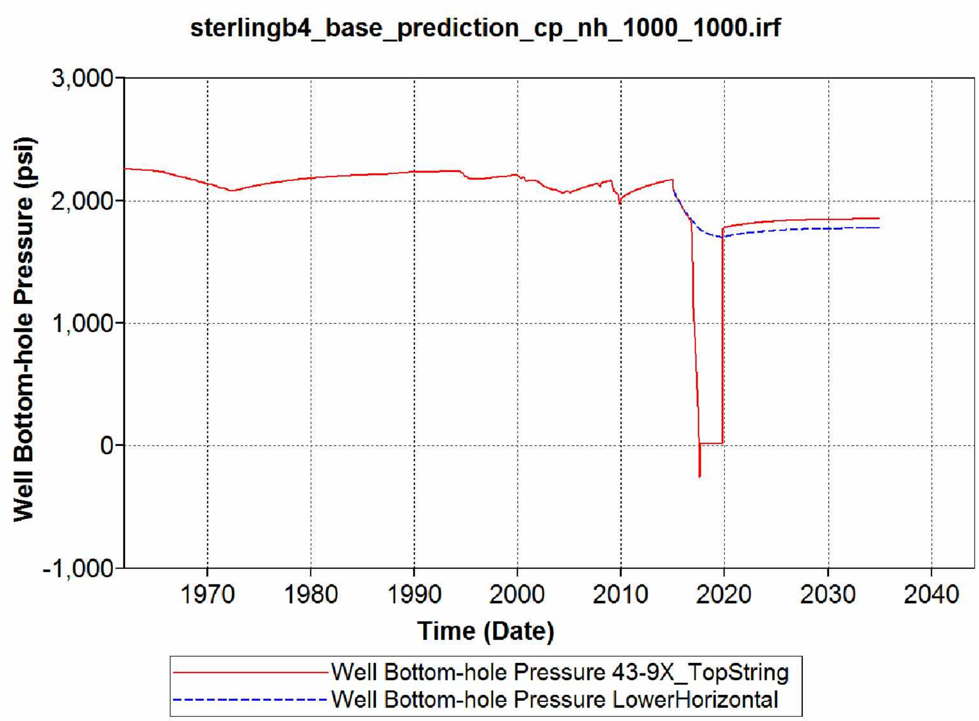

Figure 54. Pressure difference between upper vertical well and lower horizontal wells for gas production rate of 1,000 mcf/d and water production rate of 1,000 bbls/d.

In all of the above figures, the BHP of 43-9X is maintained above the BHP of the lower horizontal for a limited amount of time before the BHP of 43-9X is taken to zero psi to maintain the gas production rate. When this occurs, a significant pressure gradient develops between the lower and upper portions of the reservoir and the water sweeps upward as the lower horizontal is unable to control the gas-water contact. The time difference between when the BHP of 43-9X hits zero and when the well is shut-in is the time for the water to sweep upward and 43-9X is watered out. An example of this pressure gradient is see in Figure 55, with the associated water saturation seen in Figure 56.

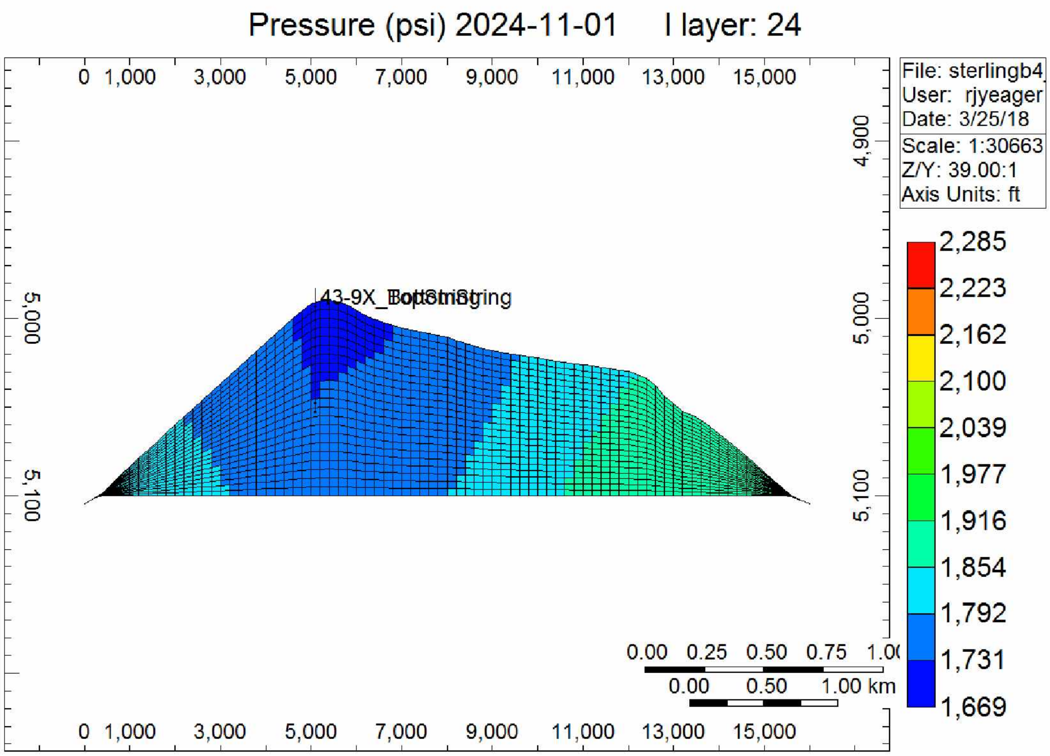

Figure 55. Pressure gradient after gas well waters out

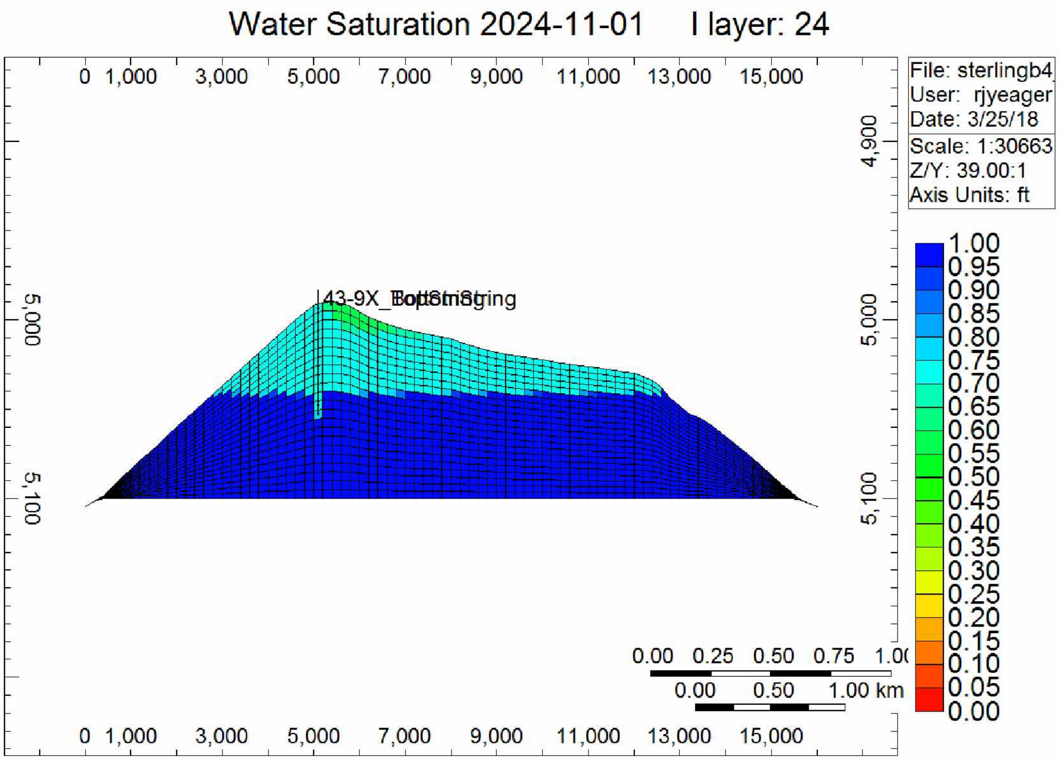

Figure 56. Water saturation after gas well waters out.

Similar to the dual-horizontal co-production, a modified step-down rate of gas production to maintain the pressure delta which controls gas-water contact was modeled and found to have deliver significantly less benefit than a stable gas production rate. The gas production rate was stepped down as the rate at which the pressure delta decreases began to accelerate. As mentioned, this method extends the production life, but delivers significantly less benefit.

Therefore, two means of co-production met the recovery threshold of 1 BCF and are deemed technically feasible; the second objective of the project is met by these options.

5.3 Economic Analysis

The third objective of the project is to determine optimal economics for those production strategies determined to be technically feasible. This analysis will evaluate those options for economic feasibility.

5.3.1 General Assumptions

Economic analyses included the following assumptions:

- Development costs were considered exclusive to drilling costs.
- Operational expenses were considered to be equal and applicable in all cases.

- The facility it not currently in operation, therefore all cases will assume full operational expense.
- Operational expenses escalate at 10% annually.
- Economic life considered was determined by the shut-in limits associated with the gas production wells. Therefore, evaluation life was directly tied to technical feasibility.
- Water disposal costs assumed to be $0.10 per bbl and escalates at 4% annually.
- Sales gas unit prices are determined based upon the average monthly sales price at 10%, 50%, and 90% probabilistic approach from January 2015 to January 2018. The P90, P50, and P10 sales unit prices are therefore $6.78/mscf, $7.75/mscf, and $8.53/mscf, respectively.
- Royalties and tax rates are assumed to be 15% and 21%, respectively
- Horizontal wells assumed to cost $3MM each.

5.3.2 Economic Results

The results from the economic analysis are shown in Table 7. The U.S. corporate tax rate has been historically been at 40%. Recent tax structure changes, however, have brought this down to 21%. Had this project been evaluated a year earlier, the economics would have been different, as seen in Table 8. The impact of the tax change is observed to affect and enable cases with a negative NPV between $0 and $725,000 to become positive, or four out of the 45 cases. Therefore, the tax change has enabled a few of the cases to be considered economically viable, but does not substantially impact the cases like the operational expense or the drilling costs.

Case	Gas Rate	H2O Rate	Inc. Cum. Recovery	Time	NPV	NPV	NPV
	mcf/d	bbl/d	mcf	yrs	P90	P50	P10
Co-Production: New Horizontals	200	1000	1,513,380	20.8	($9,440,569)	($9,148,537)	($8,449,924)
	400	1000	1,546,000	10.7	($5,035,289)	($4,903,980)	($3,811,068)
	600	1000	1,442,400	6.6	($3,252,302)	($3,408,008)	($1,879,389)
	800	1000	1,313,600	4.5	($1,956,687)	($2,260,687)	($339,448)
	1000	1000	1,186,000	3.3	($1,305,930)	($1,644,423)	$369,916
Co-Production: Vertical/Horizontal	200	1000	1,460,800	20.1	($6,606,969)	($6,021,964)	($5,650,186)
	200	1500	1,460,800	20.1	($6,774,664)	($6,189,660)	($5,817,881)
	400	1000	1,436,600	9.9	($2,228,572)	($1,562,304)	($1,142,300)
	400	1500	2,229,145	18.6	($3,003,393)	($2,047,073)	($1,453,687)
	600	1000	1,259,800	5.8	($793,370)	($99,913)	$340,788
	600	1500	2,276,135	14.9	$8,161	$1,231,071	$2,008,248
	800	1000	1,343,655	5.7	$637,012	$1,552,312	$2,133,999
	800	1500	2,230,999	12.8	$2,372,205	$3,892,948	$4,859,401
	1000	1000	1,274,383	4.8	$1,485,730	$2,485,659	$3,121,129
	1000	1500	2,164,127	11.9	$4,561,122	$6,391,280	$7,554,372

Table 7. Economic results overview with 21% tax rate.

Case	Gas Rate	H2O Rate	Inc. Cum. Recovery	Time	NPV	NPV	NPV
	mcf/d	bbl/d	mcf	yrs	P90	P50	P10
Co-Production: New Horizontals	200	1000	1,513,380	20.8	($9,440,569)	($8,834,861)	($8,449,924)
	400	1000	1,546,000	10.7	($5,203,044)	($4,593,211)	($4,213,747)
	600	1000	1,442,400	6.6	($3,738,497)	($3,053,023)	($2,617,395)
	800	1000	1,313,600	4.5	($2,653,558)	($1,838,698)	($1,320,844)
	1000	1000	1,186,000	3.3	($2,058,116)	($1,200,070)	($654,769)
Co-Production: Vertical/Horizontal	200	1000	1,460,800	20.1	($6,606,969)	($6,021,964)	($5,650,186)
	200	1500	1,460,800	20.1	($6,774,664)	($6,189,660)	($5,817,881)
	400	1000	1,436,600	9.9	($2,420,267)	($1,908,079)	($1,589,089)
	400	1500	2,229,145	18.6	($3,175,055)	($2,370,839)	($1,887,120)
	600	1000	1,259,800	5.8	($1,324,078)	($797,402)	($462,692)
	600	1500	2,276,135	14.9	($715,321)	$213,472	$803,732
	800	1000	1,343,655	5.7	($237,713)	$457,453	$899,240
	800	1500	2,230,999	12.8	$1,080,156	$2,235,150	$2,969,166
	1000	1000	1,274,383	4.8	$406,883	$1,166,323	$1,648,958
	1000	1500	2,164,127	11.9	$2,742,624	$4,132,618	$5,015,979

Table 8. Economic results overview with 40% tax rate.

As observed the cases with higher gas rates result in a greater net present value. Many cases, in fact, are in excess of the "walk away" option wherein the asset is sold. The drilling costs are a significant initial hurdle to both all options, but especially so with the dual-horizontal option with two new horizontals where only one case is economically feasible. The vertical/horizontal option is preferred, as the initial capital costs would be halved with only a single new well being drilled and results in a higher average cumulative recovery.

Maximizing cash flow would bias towards a higher production rate. Because the facility is not currently in operation, this revenue stream would solely bear the operational expense. This cost is assumed to escalate at 10% per year—significantly more than the commodity cost of 4% per year. Therefore, maximizing NPV would require minimizing time to cumulative recovery

At P50 sales prices, co-production becomes a technical and economically feasible option offering over $6MM in cumulative cash flow when water production is held at 1,500 bbl/d and gas production at 1,000 mcf/d.

Diagrams illustrating the variable sensitivity is shown in Figures 57 and 58. Controlling for net present value, gas rate is the most sensitive variable. When controlling for cumulative gas recovery, the water production rate is the most sensitive variable.

The NPV sensitivity for gas rate is the average NPV for all cases run at the 200 mcf/d gas rate at the low end and the average NPV for all cases run at the 1,000 mcf/d rate. The low end of the water rate is at 1,000 bbl/d of water production and the high end is 1,500 bbl/d. The unit price sensitivity is the average NPV for all cases run at the P90 price for the low end and P90 at the high end. The tax rate is the average NPV for all cases at the 40% rate for the low end and 21% for the high end. The gas rate is the most sensitive variable affecting NPV.

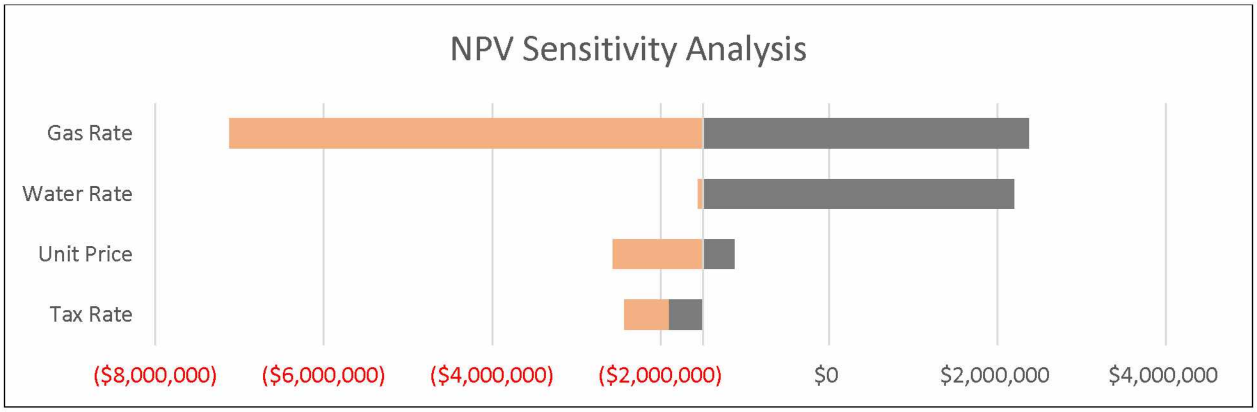

Figure 57. NPV Sensitivity Analysis

The sensitivity of the water and gas production rates to the cumulative gas recovery are seen in Figure 58. The water rate was held at 1,000 bbl/d on the low end and 1,500 bbl/d on the high end. The gas rate is seen at 200 mcf/d at the low end and 1,000 mcf/d at the high end. The water rate is the most sensitive variable affecting the cumulative gas production.

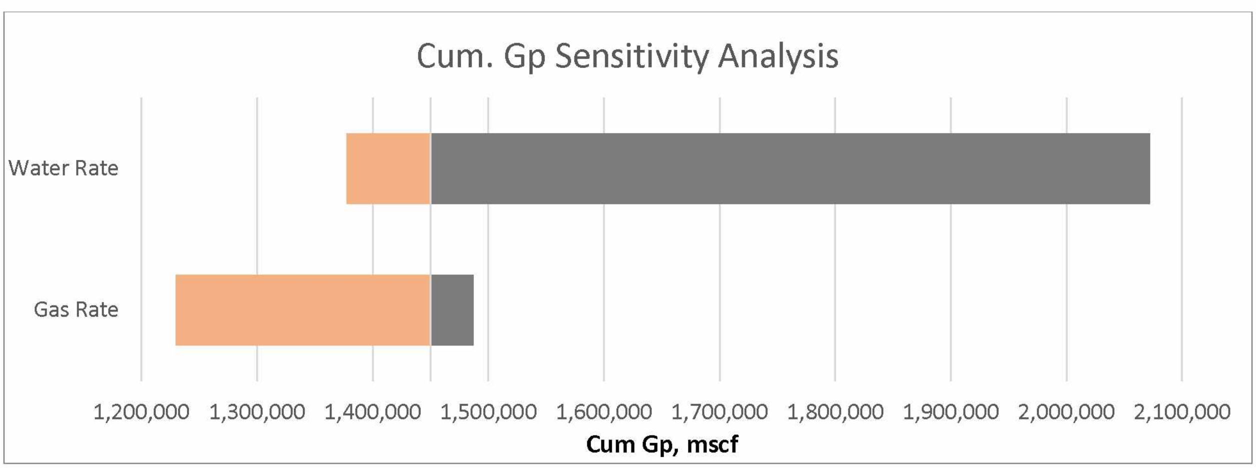

Figure 58. Cumulative Gas Production Sensitivity Analysis

6.0 Conclusions

The Sterling B4 formation is an attractive gas-on-water reservoir. Volumetrics determined the OGIP to be approximately 13.9 BCF and material balance determined OGIP to be approximately 27 BCF. Due to the large difference between these numbers a waterdrive was suspected and confirmed with diagnostic plots.

Future production from this reservoir would require understanding and challenging problems from the past and dealing with watered-out wells. This would require some production scheme which controls the gas-water contact mobility.

The preferred technical alternative aligns with the preferred economic alternative: vertical/horizontal co-production. This alternative is an attractive target, and could increase in greater value should operational expense be shared across multiple revenue streams.

Co-production is seen to be to be technically feasible, as the GWC may be controlled by sufficiently high water production from below the GWC to maximize the pressure delta. So long as the pressure in the gas leg is greater than the pressure in the water leg, the system requires the gas-water contact to either stay immobile or even lower. However, as gas production reduces the pressure in the gas zone, the pressure delta swings to the opposite configuration and a pressure gradient, which allows water to again sweep upwards.

The root cause of the failed attempt to perform co-production through Well 43-9X is believed to have been a poorly performed completion at the gravel packer, but modeling results have determined the dual completion in a vertical well would have yielded significantly less than a vertical/horizontal configuration. The vertical co-production method has a local effect, but lacks the ability to manage the gas-water contact in a reservoir of this shape.

Excluding any economic analysis, the co-production methods utilizing lower water-producing horizontal wells is determined to be the most attractive production method. As mentioned, so long as the pressure delta between the gas and water producing wells is maintained above a critical rate, gas will continue to produce.

Based upon the results from this analysis, the most economically feasible solution is conventional production from the upper perforation of existing Well 43-9X, coupled with a lower horizontal well producing water.

The results have demonstrated that minimizing the time to cumulative recovery, maximizing the gas production rate, and maximizing the water production rate is the most feasible solution for the commercialization of the gas.

Commercial opportunities could be enhanced by sharing the operational expense associated with operating a vacant facility across other revenue streams. The Sterling sands are between the Beluga and Tyonek formations, both of which appear to hold significant gas reserves. Engineering analysis of the Tyonek and Beluga formations bears merit. The largest initial expense on any option is drilling costs. Therefore, any new infill drilling should maximize perforations by targeting as many as formations possible in any single well.

Further, the water mobility issue may be continuous throughout the strata due to the relatively close proximity between the other formations. Thus, a co-production method simultaneously producing from several formations may be mechanically limited due to the need to independently control and maintain each production optimization.

7.0 Recommendations for Future Work

No core analyses were available for this project. Completing lab analyses on the formation water is recommended to develop a more accurate reservoir model.

A feasibility study of the Tyonek and Beluga formations similar to this effort bears merit to determine whether a large development plan inclusive of Sterling B4 co-production would bear under an economic analysis.

8.0 References

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9.0 Appendices

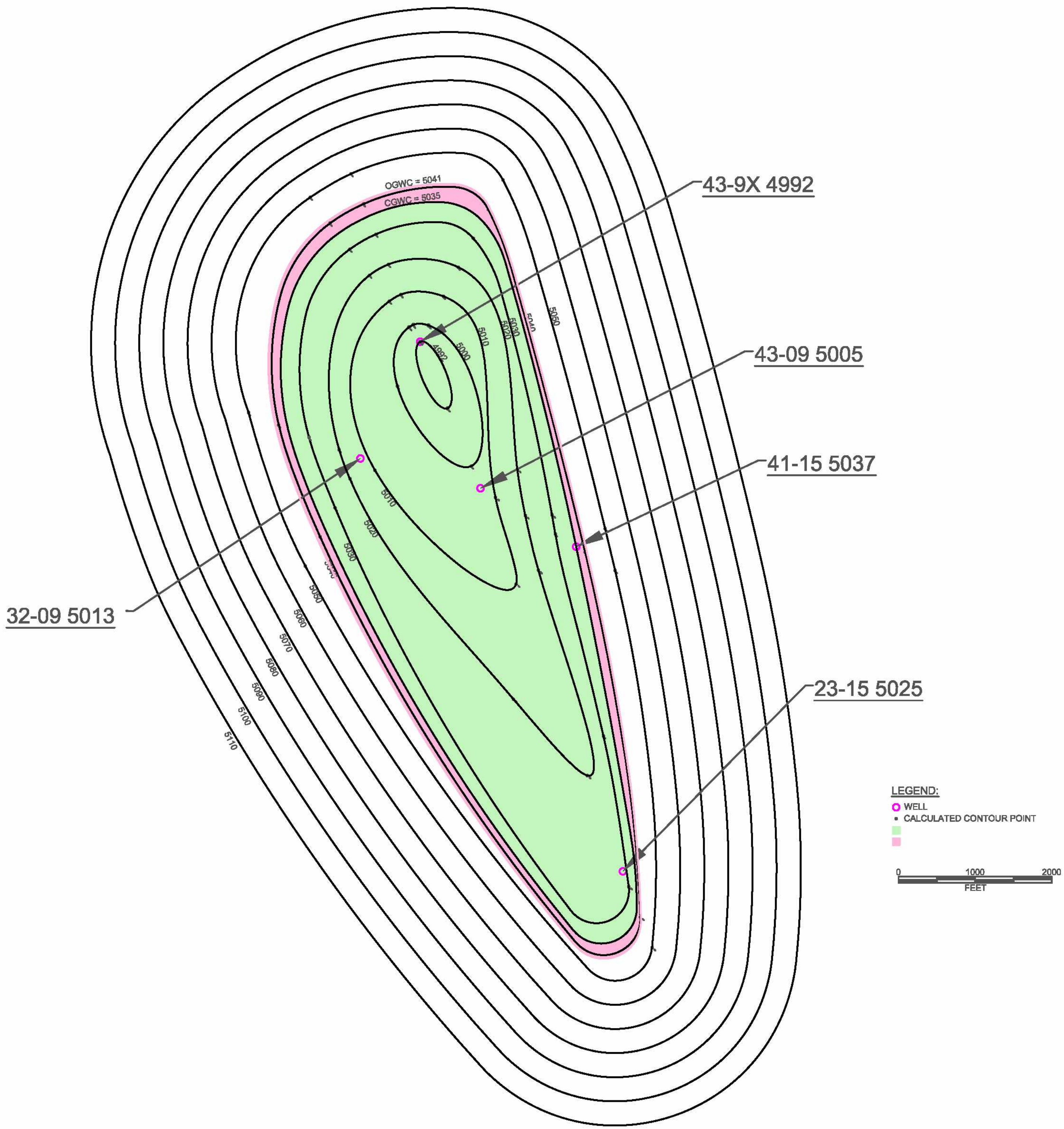
A. Structure formation as developed from well type logs.

B. Mapped type logs used for structure development

C. Detailed Reservoir and Economic Information for Dual Horizontal Co-Production

D. Detailed Reservoir and Economic Information for Horizontal/Vertical Co-Production

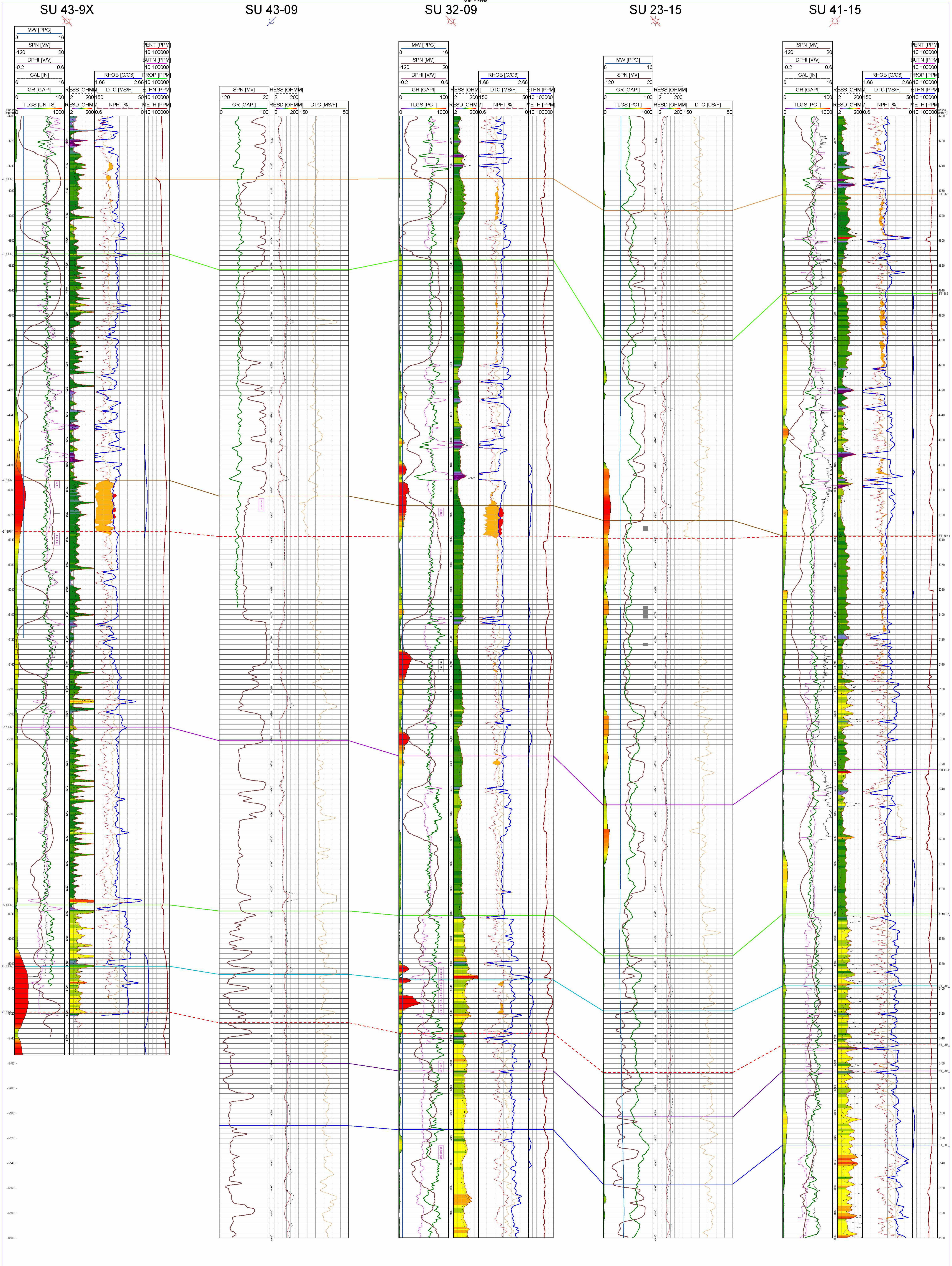
A. Structure formation as developed from well type logs.



STERLING FIELD

STRUCTURE DEVELOPED FROM WELL LOGS WITH SMOOTHED CONTOURS

B. Mapped type logs used for structure development

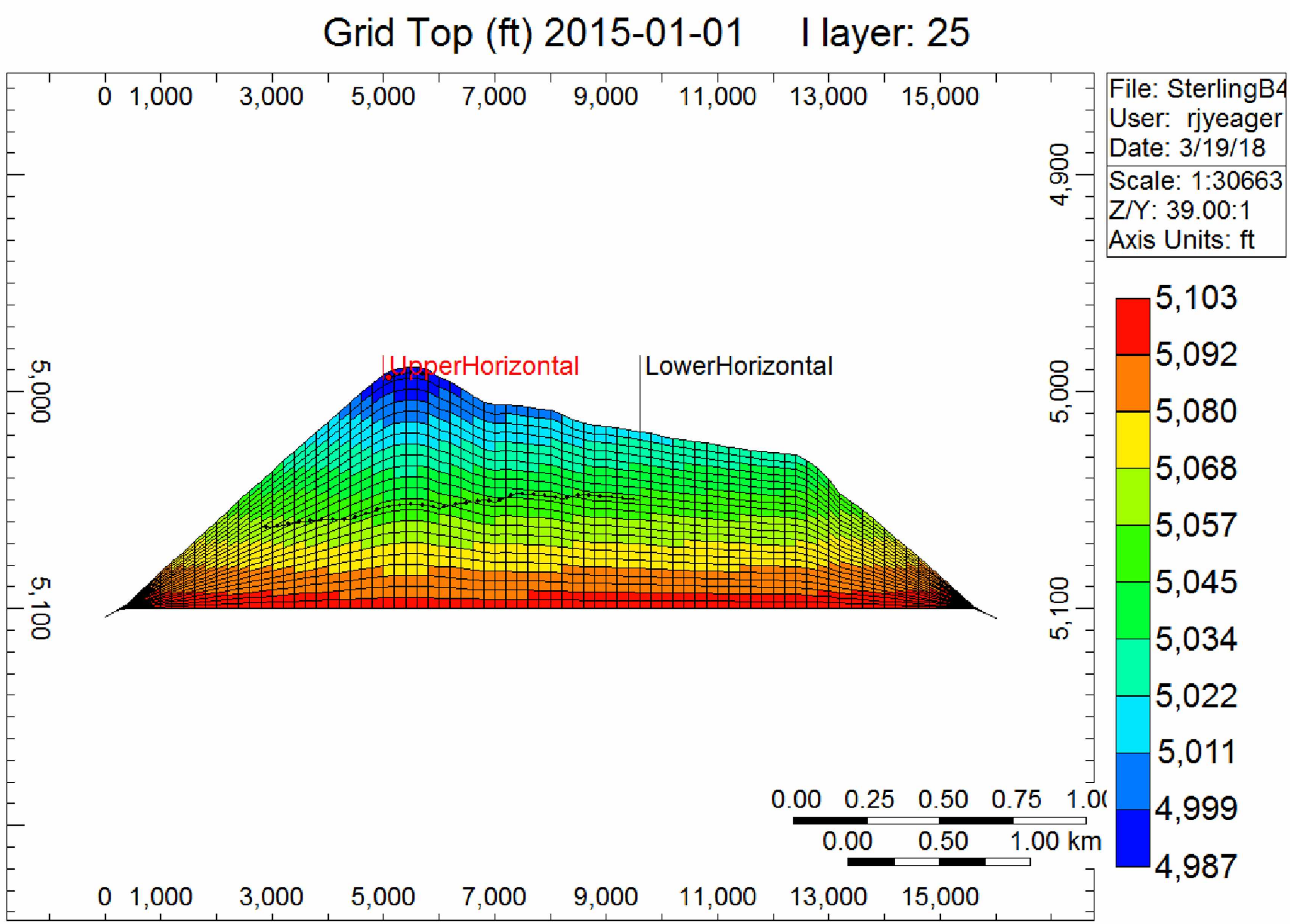


NORTH KENAI
SU 43-9X
SU 43-09
SU 32-09
SU 23-15
SU 41-15
MW [PPG]
SPN [MV]
DPHI [V/V]
CAL [IN]
GR [GAPI]
TLGS [UNITS]
TLGS [PCT]
RESS [OHMM]
RESD [OHMM]
RHOB [G/C3]
DTC [MS/F]
DTC [US/F]
NPHI [%]
PENT [PPM]
BUTN [PPM]
PROP [PPM]
ETHN [PPM]
METH [PPM]

C. Detailed Reservoir and Economic Information for Dual Horizontal Co-Production

Co-Production

- Gas: new upper horizontal well
  - Producing at 200, 400, 600, 800, 1000 MCFD
- Water: new lower horizontal well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4,900
5,000
5,100
UpperHorizontal
LowerHorizontal
File: SterlingB4
User: rjyeager
Date: 3/19/18
Scale: 1:30663
Z/Y: 39.00:1
Axis Units: ft
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5,092
5,080
5,068
5,057
5,045
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5,022
5,011
4,999
4,987
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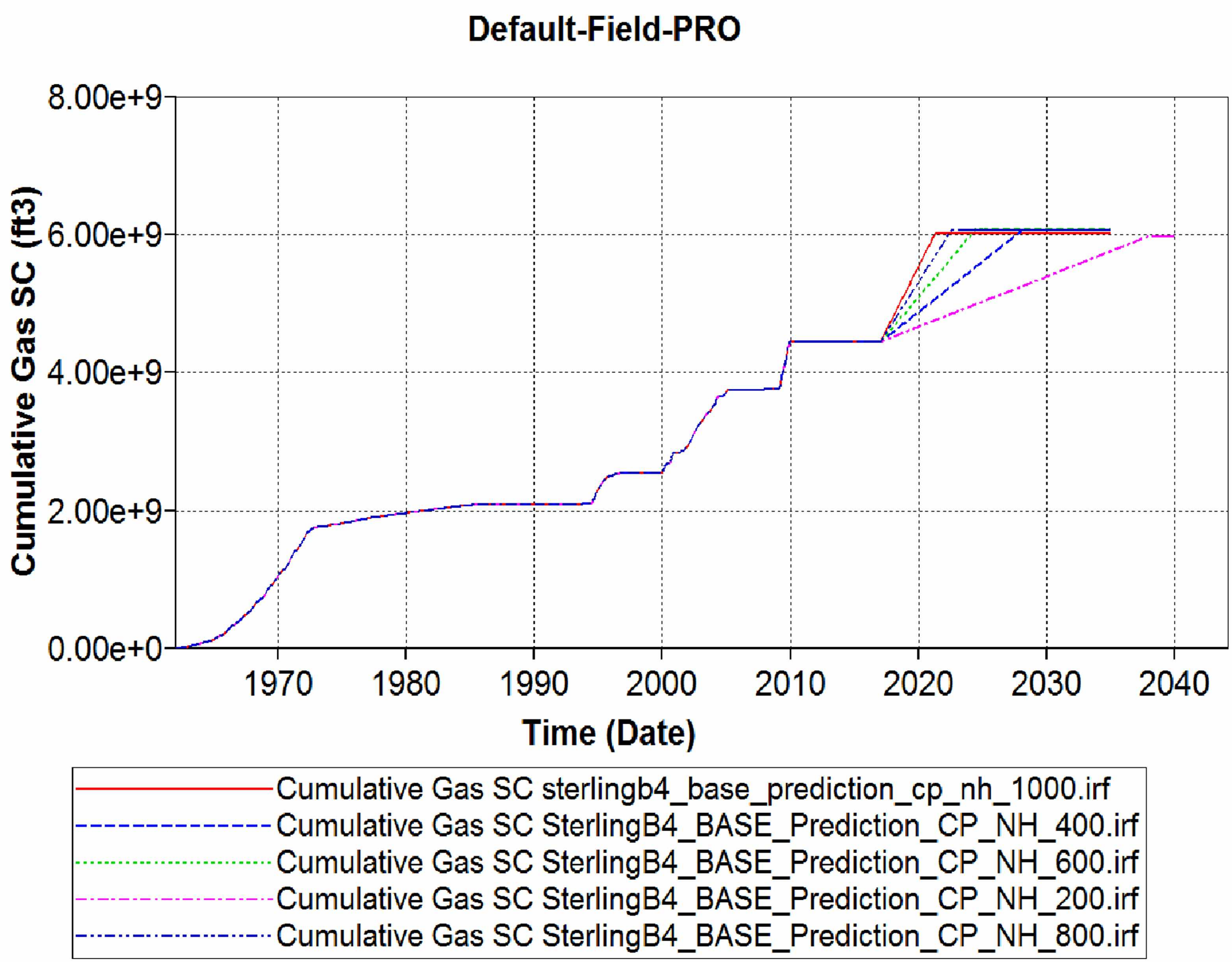
0.00 0.50 1.00 km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Cumulative Gas SC (ft3)
1970
1980
1990
2000
2010
2020
2030
2040
Time (Date)
Cumulative Gas SC sterlingb4_base_prediction_cp_nh_1000.irf
Cumulative Gas SC SterlingB4_BASE_Prediction_CP_NH_400.irf
Cumulative Gas SC SterlingB4_BASE_Prediction_CP_NH_600.irf
Cumulative Gas SC SterlingB4_BASE_Prediction_CP_NH_200.irf
Cumulative Gas SC SterlingB4_BASE_Prediction_CP_NH_800.irf

CoProduction

Horizontal well in upper formation to produce gas
Horizontal well below GWC to control the contact location
No new equipment
$3MM per horizontal well
Depreciation/amortization of facility is not considered as it is common to all cases
Depreciation/amortization will only be considered if and exclusive to newly acquired equipment

Acquisition:	$0			
Development:	$6,000,000			
Equipment:	$0	No new equipment		
Working Capital:	$0			
Evaluation Life:	-	Years		
Equipment Depreciation:	-	year (MACRS, time 0, half year)		
Salvage Value:	$0	EOY5		
Tax Rate:	40%			
Royalties:	15%			
Operating Costs:	($500,000)	@ Y1 @ escalate:		10%
Production (Y1-Y20):	200	MSCF/D		
Annual reduction:	-	MSCF/D		
Operating Days/Yr	350	days		
Unit Price:	$3.50	/MSCF/D		
Escalation:	4%			
Water disposal costs	$0.10	/bbl		
Gas/water separation costs	$0.10	/bbl		
Gas compression costs	$0.10	/mcf		
Minimum DCFROR:	15.00%			

Rate

Gas (mcf/d) Water (bbl/d)

200

Net Present Value

($11,297,322)

Year	Upper Gas Production (mcf)	Lower Gas Production	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	Gas/Water Separation	Gas Compression	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounte
0	72,642	-	363,211	$254,247.84	($38,137.18)	$216,110.66	($500,000)	-	-	($36,321)	$0	0	($6,000,000)	0	($6,320,210)	$0	($6,320,210)	$0	($6,320,210)	($6,320,210)
1	72,642	-	363,211	$264,417.75	($39,662.66)	$224,755.09	($550,000)	-	-	($37,774)	$0	0	0	0	($363,019)	$0	($363,019)		($363,019)	($315,669)
2	72,642	-	363,211	$274,994.46	($41,249.17)	$233,745.29	($605,000)	-	-	($39,285)	$0	0	0	0	($410,540)	$0	($410,540)		($410,540)	($310,427)
3	72,642	-	363,211	$285,994.24	($42,899.14)	$243,095.11	($665,500)	-	-	($40,856)	$0	0	0	0	($463,261)	$0	($463,261)		($463,261)	($304,602)
4	72,642	-	363,211	$297,434.01	($44,615.10)	$252,818.91	($732,050)	-	-	($42,491)	$0	0	0	0	($521,722)	$0	($521,722)		($521,722)	($298,296)
5	72,642	-	363,211	$309,331.37	($46,399.71)	$262,931.67	($805,255)	-	-	($44,190)	$0	0	0	0	($586,514)	$0	($586,514)		($586,514)	($291,601)
6	72,642	-	363,211	$321,704.63	($48,255.69)	$273,448.93	($885,781)	-	-	($45,958)	$0	0	0	0	($658,289)	$0	($658,289)		($658,289)	($284,597)
7	72,642	-	363,211	$334,572.81	($50,185.92)	$284,386.89	($974,359)	-	-	($47,796)	$0	0	0	0	($737,768)	$0	($737,768)		($737,768)	($277,354)
8	72,642	-	363,211	$347,955.72	($52,193.36)	$295,762.37	($1,071,794)	-	-	($49,708)	$0	0	0	0	($825,740)	$0	($825,740)		($825,740)	($269,936)
9	72,642	-	363,211	$361,873.95	($54,281.09)	$307,592.86	($1,178,974)	-	-	($51,696)	$0	0	0	0	($923,077)	$0	($923,077)		($923,077)	($262,396)
10	72,642	-	363,211	$376,348.91	($56,452.34)	$319,896.58	($1,296,871)	-	-	($53,764)	$0	0	0	0	($1,030,739)	$0	($1,030,739)		($1,030,739)	($254,783)
11	72,642	-	363,211	$391,402.87	($58,710.43)	$332,692.44	($1,426,558)	-	-	($55,915)	$0	0	0	0	($1,149,781)	$0	($1,149,781)		($1,149,781)	($247,138)
12	72,642	-	363,211	$407,058.98	($61,058.85)	$346,000.14	($1,569,214)	-	-	($58,151)	$0	0	0	0	($1,281,365)	$0	($1,281,365)		($1,281,365)	($239,496)
13	72,642	-	363,211	$423,341.34	($63,501.20)	$359,840.14	($1,726,136)	-	-	($60,477)	$0	0	0	0	($1,426,773)	$0	($1,426,773)		($1,426,773)	($231,890)
14	72,642	-	363,211	$440,275.00	($66,041.25)	$374,233.75	($1,898,749)	-	-	($62,896)	$0	0	0	0	($1,587,412)	$0	($1,587,412)		($1,587,412)	($224,347)
15	72,642	-	363,211	$457,886.00	($68,682.90)	$389,203.10	($2,088,624)	-	-	($65,412)	$0	0	0	0	($1,764,833)	$0	($1,764,833)		($1,764,833)	($216,888)
16	72,642	-	363,211	$476,201.44	($71,430.22)	$404,771.22	($2,297,486)	-	-	($68,029)	$0	0	0	0	($1,960,744)	$0	($1,960,744)		($1,960,744)	($209,534)
17	72,642	-	363,211	$495,249.49	($74,287.42)	$420,962.07	($2,527,235)	-	-	($70,750)	$0	0	0	0	($2,177,023)	$0	($2,177,023)		($2,177,023)	($202,302)
18	72,642	-	363,211	$515,059.47	($77,258.92)	$437,800.55	($2,779,959)	-	-	($73,580)	$0	0	0	0	($2,415,738)	$0	($2,415,738)		($2,415,738)	($195,204)
19	72,642	-	363,211	$535,661.85	($80,349.28)	$455,312.57	($3,057,955)	-	-	($76,523)	$0	0	0	0	($2,679,165)	$0	($2,679,165)		($2,679,165)	($188,252)
19.83	60,293	-	363,211	$459,310.62	($68,896.59)	$390,414.02	($2,747,040)	-	-	($79,055)	$0	0	0	0	($2,435,682)	$0	($2,435,682)		($2,435,682)	($152,399)

Rate

400 mcf/d

Net Present Value

($7,631,082)

Year	US Gas Production (mcf)	LS Gas Production	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	Gas/Water Separation	Gas Compression	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted C
0	144,938	-	362,344	$507,281.25	($76,092.19)	$431,189.06	($500,000)	-	-	($36,234)	$0	($6,000,000)	$0	0	($6,105,045)	$0	($6,105,045)	$0	($6,105,045)	($6,105,045)
1	144,938	-	362,344	$527,572.50	($79,135.88)	$448,436.63	($550,000)	-	-	($37,684)	$0	0	0	0	($139,247)	$0	($139,247)		($139,247)	($121,084)
2	144,938	-	362,344	$548,675.40	($82,301.31)	$466,374.09	($605,000)	-	-	($39,191)	$0	0	0	0	($177,817)	$0	($177,817)		($177,817)	($134,455)
3	144,938	-	362,344	$570,622.42	($85,593.36)	$485,029.05	($665,500)	-	-	($40,759)	$0	0	0	0	($221,230)	$0	($221,230)		($221,230)	($145,462)
4	144,938	-	362,344	$593,447.31	($89,017.10)	$504,430.22	($732,050)	-	-	($42,389)	$0	0	0	0	($270,009)	$0	($270,009)		($270,009)	($154,378)
5	144,938	-	362,344	$617,185.21	($92,577.78)	$524,607.42	($805,255)	-	-	($44,085)	$0	0	0	0	($324,732)	$0	($324,732)		($324,732)	($161,449)
6	144,938	-	362,344	$641,872.61	($96,280.89)	$545,591.72	($885,781)	-	-	($45,848)	$0	0	0	0	($386,037)	$0	($386,037)		($386,037)	($166,894)
7	144,938	-	362,344	$667,547.52	($100,132.13)	$567,415.39	($974,359)	-	-	($47,682)	$0	0	0	0	($454,625)	$0	($454,625)		($454,625)	($170,910)
8	144,938	-	362,344	$694,249.42	($104,137.41)	$590,112.01	($1,071,794)	-	-	($49,589)	$0	0	0	0	($531,272)	$0	($531,272)		($531,272)	($173,674)
9	144,938	-	362,344	$722,019.40	($108,302.91)	$613,716.49	($1,178,974)	-	-	($51,573)	$0	0	0	0	($616,830)	$0	($616,830)		($616,830)	($175,342)
9.67	97,108	-	362,344	$496,633.49	($74,495.02)	$422,138.47	($842,000)	-	-	($52,946)	$0	0	0	0	($472,807)	$0	($472,807)		($472,807)	($122,387)

Rate

600 mcf/d

Net Present Value

($5,866,388)

Year	US Gas Production (mcf)	LS Gas Production	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	Gas/Water Separation	Gas Compression	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted C
0	219,099	-	365,165	$766,845.57	($115,026.84)	$651,818.73	($500,000)	-	-	($36,516)	$0	($6,000,000)	$0	0	($5,884,698)	$0	($5,884,698)	$0	($5,884,698)	($5,884,698)
1	219,099	-	365,165	$797,519.39	($119,627.91)	$677,891.48	($550,000)	-	-	($37,977)	$0	0	0	0	$89,914	($35,966)	$53,949		$53,949	$46,912
2	219,099	-	365,165	$829,420.17	($124,413.03)	$705,007.14	($605,000)	-	-	($39,496)	$0	0	0	0	$60,511	($24,204)	$36,307		$36,307	$27,453
3	219,099	-	365,165	$862,596.97	($129,389.55)	$733,207.43	($665,500)	-	-	($41,076)	$0	0	0	0	$26,631	($10,653)	$15,979		$15,979	$10,506
4	219,099	-	365,165	$897,100.85	($134,565.13)	$762,535.73	($732,050)	-	-	($42,719)	$0	0	0	0	($12,233)	$0	($12,233)		($12,233)	($6,994)
5	219,099	-	365,165	$932,984.89	($139,947.73)	$793,037.15	($805,255)	-	-	($44,428)	$0	0	0	0	($56,646)	$0	($56,646)		($56,646)	($28,163)
5.58	127,077	-	365,165	$553,581.97	($83,037.30)	$470,544.68	($493,593)	-	-	($45,450)	$0	0	0	0	($68,499)	$0	($68,499)		($68,499)	($31,404)

Rate

800 mcf/d

Net Present Value

($5,151,446)

Year

Year	US Gas Production (mcf)	LS Gas Production	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	Gas/Water Separation	Gas Compression	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted C
0	291,911	-	364,889	$1,021,688.89	($153,253.33)	$868,435.56	($500,000)	-	-	($36,489)	$0	($6,000,000)	$0	0	($5,668,053)	$0	($5,668,053)	$0	($5,668,053)	($5,668,053)
1	291,911	-	364,889	$1,062,556.44	($159,383.47)	$903,172.98	($550,000)	-	-	($37,948)	$0	0	0	0	$315,225	($126,090)	$189,135		$189,135	$164,465
2	291,911	-	364,889	$1,105,058.70	($165,758.81)	$939,299.90	($605,000)	-	-	($39,466)	$0	0	0	0	$294,834	($117,933)	$176,900		$176,900	$133,762
3	291,911	-	364,889	$1,149,261.05	($172,389.16)	$976,871.89	($665,500)	-	-	($41,045)	$0	0	0	0	$270,327	($108,131)	$162,196		$162,196	$106,647
4	291,911	-	364,889	$1,195,231.49	($179,284.72)	$1,015,946.77	($732,050)	-	-	($42,687)	$0	0	0	0	$241,210	($96,484)	$144,726		$144,726	$82,748
4.5	145,956	-	364,889	$609,450.87	($91,417.63)	$518,033.24	($383,890)	-	-	($43,532)	$0	0	0	0	$90,611	($36,244)	$54,366		$54,366	$28,986

Rate

1000 mcf/d

Net Present Value

($4,688,388)

Year

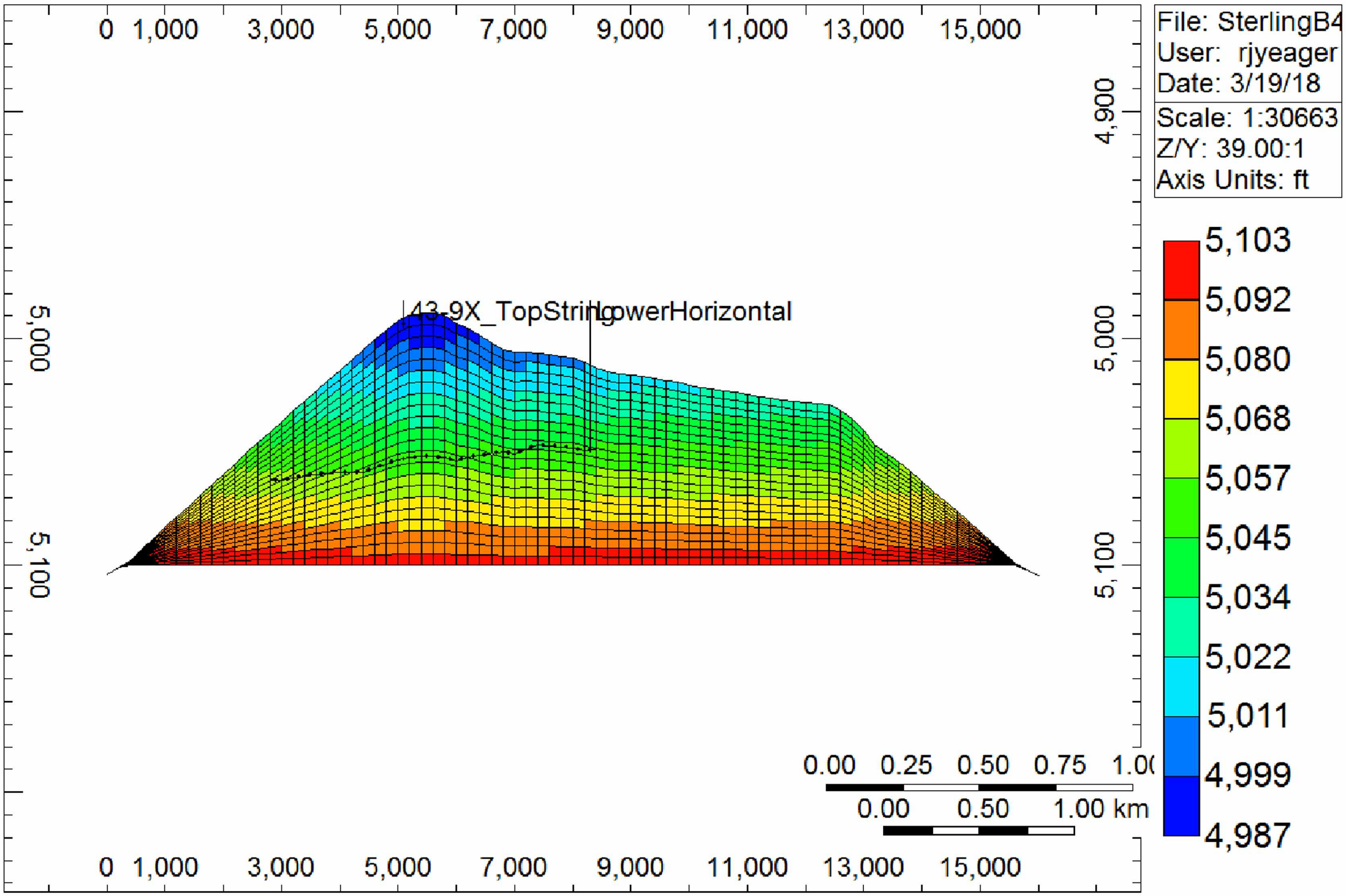
Year	Gas Production		Water Production	Revenue	Royalties	Net Revenue	Operations	Gas/Water Separation	Gas Compression	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted Ca
0	364,923	-	364,923	$1,277,230.77	($191,584.62)	$1,085,646.15	($500,000)	-	-	($36,492)	$0	($6,000,000)	$0	0	($5,450,846)	$0	($5,450,846)	$0	($5,450,846)	($5,450,846)
1	364,923	-	364,923	$1,328,320.00	($199,248.00)	$1,129,072.00	($550,000)	-	-	($37,952)	$0	0	0	0	$541,120	($216,448)	$324,672		$324,672	$282,323
2	364,923.08	-	364,923	$1,381,452.80	($207,217.92)	$1,174,234.88	($605,000)	-	-	($39,470)	$0	0	0	0	$529,765	($211,906)	$317,859		$317,859	$240,347
3	364,923.08	-	364,923	$1,436,710.91	($215,506.64)	$1,221,204.28	($665,500)	-	-	($41,049)	$0	0	0	0	$514,655	($205,862)	$308,793		$308,793	$203,037
3.25	91,230.77	-	364,923	$362,716.85	($54,407.53)	$308,309.32	($170,387)	-	-	($41,453)	$0	0	0	0	$96,469	($38,588)	$57,881		$57,881	$36,751

D. Detailed Reservoir and Economic Information for Horizontal/Vertical Co-Production

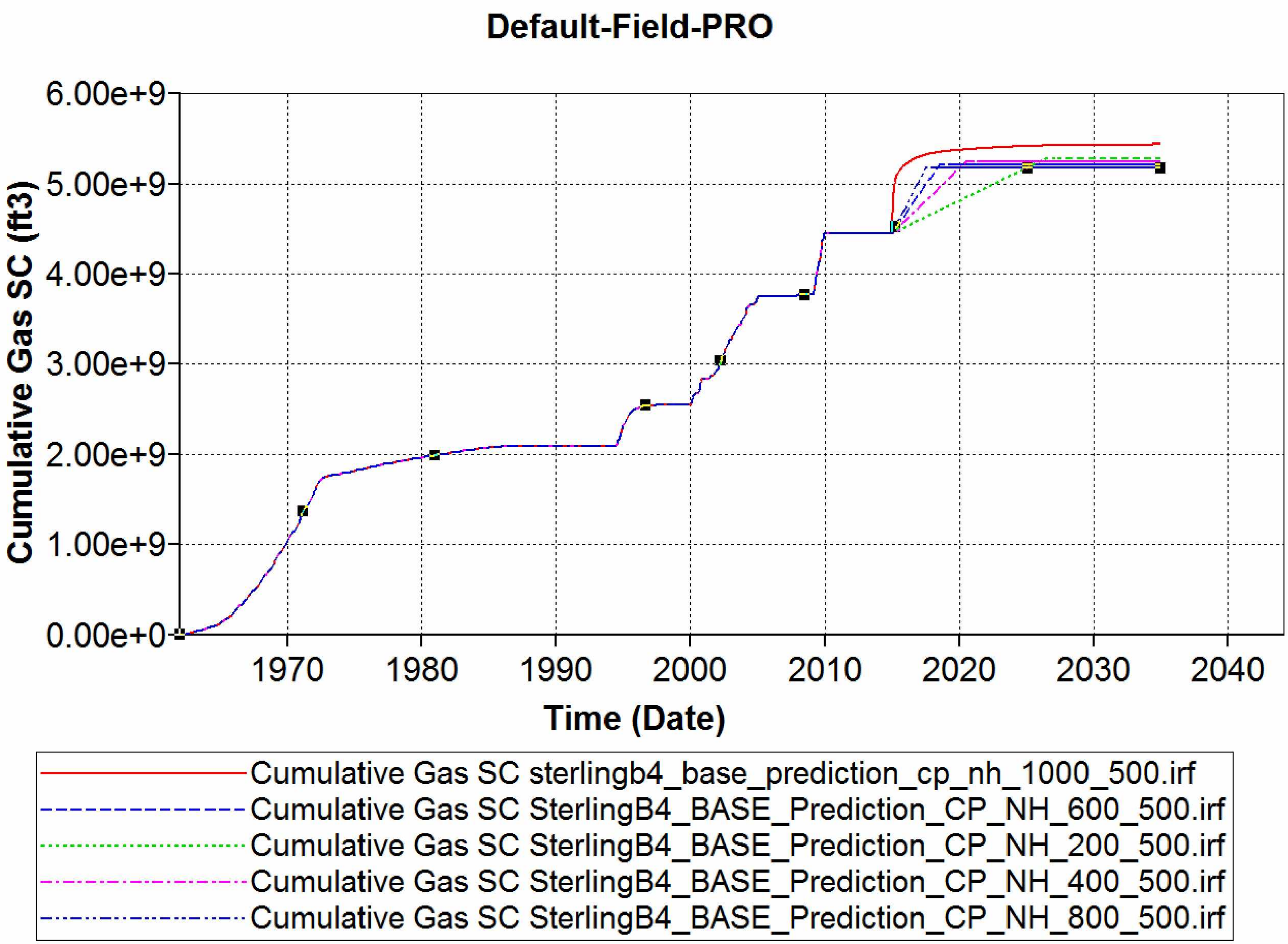
Co-Production

- Gas: existing upper perf in 43-9X
  - Producing at 200, 400, 600, 800, 1000 MCFD
- Water: new lower horizontal well
  - Producing at 500, 1000, 1500 BBLD
  - Modified water production rates significantly affect incremental recovery

Grid Top (ft) 2015-01-01   I layer: 25



- Water production rate = 500 bbl/d



CoProduction

Horizontal well in upper formation to produce gas
Horizontal well below GWC to control the contact location
No new equipment

$3MM per horizontal well
Depreciation/amortization of facility is not considered as it is common to all cases
Depreciation/amortization will only be considered if and exclusive to newly acquired equipment

Acquisition:	$0		
Development:	$3,000,000		
Equipment:	$0	No new equipment	
Working Capital:	$0		
Evaluation Life:	-	Years	
Equipment Depreciation:	-	year (MACRS, time 0, half year)	
Salvage Value:	$0	EOY5	
Tax Rate:	40%		
Royalties:	15%		
Operating Costs:	($500,000)	@ Y1 @ escalate:	10%
Production (Y1-Y20):	200	MSCF/D	
Annual reduction:	-	MSCF/D	
Operating Days/Yr	350	days	
Unit Price:	$3.50	/MSCF/D	
Escalation:	4%		
Water disposal costs	$0.10	/bbl	
Gas/water separation costs	$0.10	/bbl	
Gas compression costs	$0.10	/mcf	
Minimum DCFROR:	15.00%		

Rate

Gas (mcf/d)	Water (bbl/d)
200	500

Net Present Value

($6,245,326)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	70,000	182,500	$245,000.00	($36,750.00)	$208,250.00	($500,000)	($18,250)	$0	0		0	($310,000)	$0	($310,000)	($3,000,000)	($3,310,000)	($3,310,000)
1	70,000	182,500	$254,800.00	($38,220.00)	$216,580.00	($550,000)	($18,980)	$0	0	0	0	($352,400)	$0	($352,400)		($352,400)	($306,435)
2	70,000	182,500	$264,992.00	($39,748.80)	$225,243.20	($605,000)	($19,739)	$0	0	0	0	($399,496)	$0	($399,496)		($399,496)	($302,076)
3	70,000	182,500	$275,591.68	($41,338.75)	$234,252.93	($665,500)	($20,529)	$0	0	0	0	($451,776)	$0	($451,776)		($451,776)	($297,050)
4	70,000	182,500	$286,615.35	($42,992.30)	$243,623.05	($732,050)	($21,350)	$0	0	0	0	($509,777)	$0	($509,777)		($509,777)	($291,467)
5	70,000	182,500	$298,079.96	($44,711.99)	$253,367.97	($805,255)	($22,204)	$0	0	0	0	($574,091)	$0	($574,091)		($574,091)	($285,425)
6	70,000	182,500	$310,003.16	($46,500.47)	$263,502.69	($885,781)	($23,092)	$0	0	0	0	($645,370)	$0	($645,370)		($645,370)	($279,011)
7	70,000	182,500	$322,403.29	($48,360.49)	$274,042.79	($974,359)	($24,016)	$0	0	0	0	($724,332)	$0	($724,332)		($724,332)	($272,303)
8	70,000	182,500	$335,299.42	($50,294.91)	$285,004.50	($1,071,794)	($24,976)	$0	0	0	0	($811,766)	$0	($811,766)		($811,766)	($265,368)
9	70,000	182,500	$348,711.39	($52,306.71)	$296,404.68	($1,178,974)	($25,975)	$0	0	0	0	($908,545)	$0	($908,545)		($908,545)	($258,265)
10	70,000	182,500	$362,659.85	($54,398.98)	$308,260.87	($1,296,871)	($27,014)	$0	0	0	0	($1,015,625)	$0	($1,015,625)		($1,015,625)	($251,047)
10.5	35,000	182,500	$184,920.97	($27,738.14)	$157,182.82	($680,085)	($27,549)	$0	0	0	0	($550,452)	$0	($550,452)		($550,452)	($126,880)

Rate

Gas (mcf/d)	Water (bbl/d)
400	500

Net Present Value

($3,730,635)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	140,000	182,500	$490,000.00	($73,500.00)	$416,500.00	($500,000)	($18,250)	$0	0		0	($101,750)	$0	($101,750)	($3,000,000)	($3,101,750)	($3,101,750)
1	140,000	182,500	$509,600.00	($76,440.00)	$433,160.00	($550,000)	($18,980)	$0	0	0	0	($135,820)	$0	($135,820)		($135,820)	($118,104)
2	140,000	182,500	$529,984.00	($79,497.60)	$450,486.40	($605,000)	($19,739)	$0	0	0	0	($174,253)	$0	($174,253)		($174,253)	($131,760)
3	140,000	182,500	$551,183.36	($82,677.50)	$468,505.86	($665,500)	($20,529)	$0	0	0	0	($217,523)	$0	($217,523)		($217,523)	($143,025)
4	140,000	182,500	$573,230.69	($85,984.60)	$487,246.09	($732,050)	($21,350)	$0	0	0	0	($266,154)	$0	($266,154)		($266,154)	($152,174)
4.5	70,000	182,500	$292,291.45	($43,843.72)	$248,447.73	($383,890)	($21,773)	$0	0	0	0	($157,215)	$0	($157,215)		($157,215)	($83,821)

Rate

Gas (mcf/d) Water (bbl/d)

600 500

Net Present Value

($2,867,801)

Year

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	210,000	182,500	$735,000.00	($110,250.00)	$624,750.00	($500,000)	($18,250)	$0	0		0	$106,500	($42,600)	$63,900	($3,000,000)	($2,936,100)	($2,936,100)
1	210,000	182,500	$764,400.00	($114,660.00)	$649,740.00	($550,000)	($18,980)	$0	0	0	0	$80,760	($32,304)	$48,456		$48,456	$42,136
2	210,000	182,500	$794,976.00	($119,246.40)	$675,729.60	($605,000)	($19,739)	$0	0	0	0	$50,990	($20,396)	$30,594		$30,594	$23,134
2.5	105,000	182,500	$405,359.81	($60,803.97)	$344,555.84	($317,265)	($20,130)	$0	0	0	0	$7,161	($2,864)	$4,297		$4,297	$3,030

Rate

Gas (mcf/d) Water (bbl/d)

800 500

Net Present Value

($2,590,841)

Year

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	280,000	182,500	$980,000.00	($147,000.00)	$833,000.00	($500,000)	($18,250)	$0	0		0	$314,750	($125,900)	$188,850	($3,000,000)	($2,811,150)	($2,811,150)
1	280,000	182,500	$1,019,200.00	($152,880.00)	$866,320.00	($550,000)	($18,980)	$0	0	0	0	$297,340	($118,936)	$178,404		$178,404	$155,134
1.5	140,000	182,500	$519,692.07	($77,953.81)	$441,738.26	($288,422)	($19,356)	$0	0	0	0	$133,960	($53,584)	$80,376		$80,376	$65,175

Rate

Gas (mcf/d) Water (bbl/d)

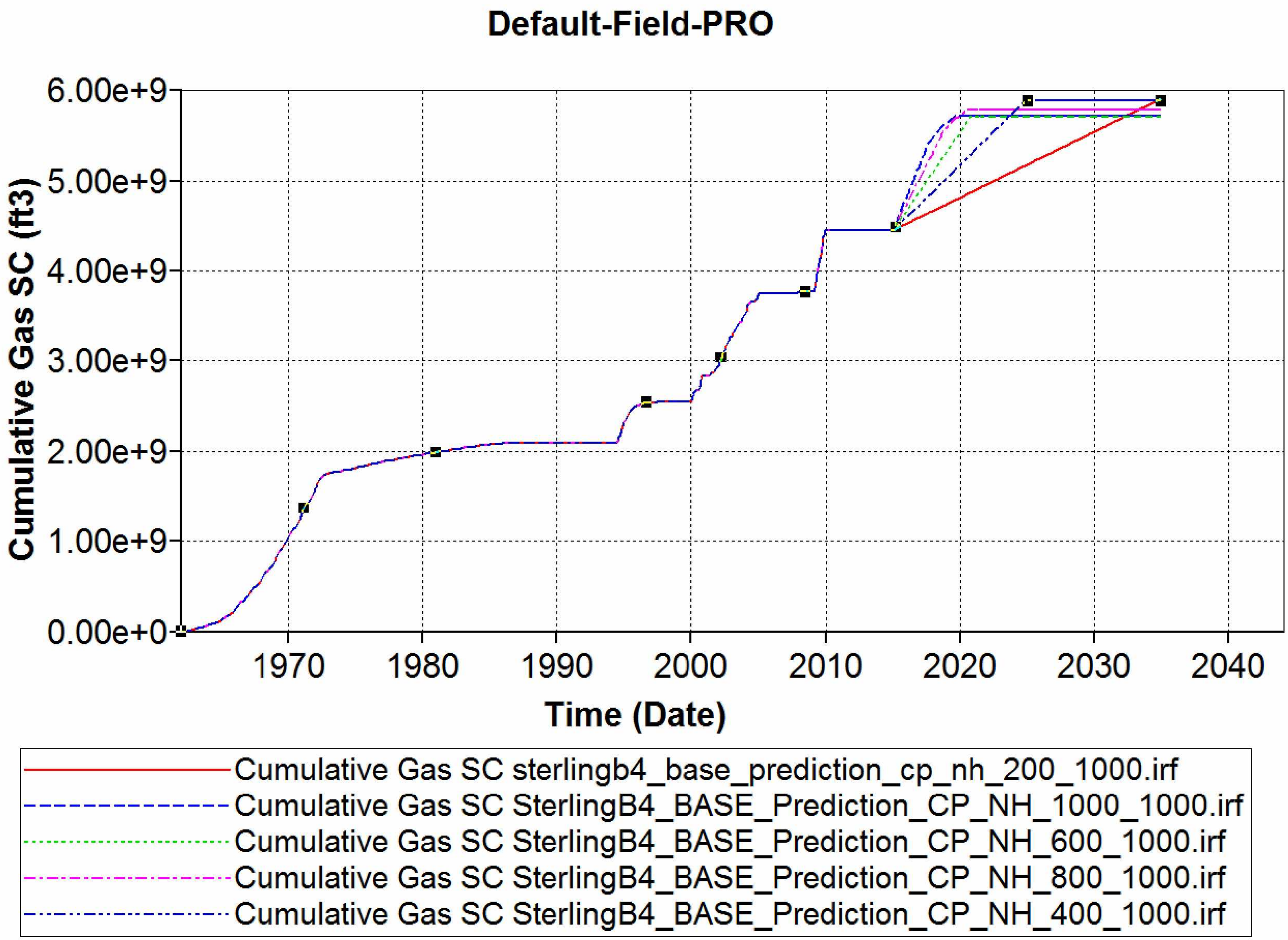
1000 500

Net Present Value

($1,679,597)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	350,000	182,500	$1,225,000.00	($183,750.00)	$1,041,250.00	($500,000)	($18,250)	$0	0		0	$523,000	($209,200)	$313,800	($3,000,000)	($2,686,200)	($2,686,200)
1	350,000	182,500	$1,274,000.00	($191,100.00)	$1,082,900.00	($550,000)	($18,980)	$0	0	0	0	$513,920	($205,568)	$308,352		$308,352	$268,132
2	350,000	182,500	$1,324,960.00	($198,744.00)	$1,126,216.00	($605,000)	($19,739)	$0	0	0	0	$501,477	($200,591)	$300,886		$300,886	$227,513
3	350,000	182,500	$1,377,958.40	($206,693.76)	$1,171,264.64	($665,500)	($20,529)	$0	0	0	0	$485,236	($194,094)	$291,142		$291,142	$191,430
4	350,000	182,500	$1,433,076.74	($214,961.51)	$1,218,115.23	($732,050)	($21,350)	$0	0	0	0	$464,715	($185,886)	$278,829		$278,829	$159,421
5	350,000	182,500	$1,490,399.81	($223,559.97)	$1,266,839.83	($805,255)	($22,204)	$0	0	0	0	$439,381	($175,752)	$263,629		$263,629	$131,070
6	350,000	182,500	$1,550,015.80	($232,502.37)	$1,317,513.43	($885,781)	($23,092)	$0	0	0	0	$408,641	($163,456)	$245,185		$245,185	$106,000
7	350,000	182,500	$1,612,016.43	($241,802.46)	$1,370,213.97	($974,359)	($24,016)	$0	0	0	0	$371,840	($148,736)	$223,104		$223,104	$83,873
8	350,000	182,500	$1,676,497.09	($251,474.56)	$1,425,022.52	($1,071,794)	($24,976)	$0	0	0	0	$328,252	($131,301)	$196,951		$196,951	$64,384
9	350,000	182,500	$1,743,556.97	($261,533.55)	$1,482,023.42	($1,178,974)	($25,975)	$0	0	0	0	$277,074	($110,830)	$166,244		$166,244	$47,257
10	350,000	182,500	$1,813,299.25	($271,994.89)	$1,541,304.36	($1,296,871)	($27,014)	$0	0	0	0	$217,419	($86,967)	$130,451		$130,451	$32,246
11	350,000	182,500	$1,885,831.22	($282,874.68)	$1,602,956.54	($1,426,558)	($28,095)	$0	0	0	0	$148,303	($59,321)	$88,982		$88,982	$19,126
12	350,000	182,500	$1,961,264.47	($294,189.67)	$1,667,074.80	($1,569,214)	($29,219)	$0	0	0	0	$68,642	($27,457)	$41,185		$41,185	$7,698
13	350,000	182,500	$2,039,715.05	($305,957.26)	$1,733,757.79	($1,726,136)	($30,388)	$0	0	0	0	($22,765)	$0	($22,765)		($22,765)	($3,700)
14	350,000	182,500	$2,121,303.65	($318,195.55)	$1,803,108.10	($1,898,749)	($31,603)	$0	0	0	0	($127,244)	$0	($127,244)		($127,244)	($17,983)
15	350,000	182,500	$2,206,155.79	($330,923.37)	$1,875,232.43	($2,088,624)	($32,867)	$0	0	0	0	($246,259)	$0	($246,259)		($246,259)	($30,264)
16	350,000	182,500	$2,294,402.03	($344,160.30)	$1,950,241.72	($2,297,486)	($34,182)	$0	0	0	0	($381,427)	$0	($381,427)		($381,427)	($40,761)
17	350,000	182,500	$2,386,178.11	($357,926.72)	$2,028,251.39	($2,527,235)	($35,549)	$0	0	0	0	($534,533)	$0	($534,533)		($534,533)	($49,672)
18	350,000	182,500	$2,481,625.23	($372,243.78)	$2,109,381.45	($2,779,959)	($36,971)	$0	0	0	0	($707,548)	$0	($707,548)		($707,548)	($57,174)
19	350,000	182,500	$2,580,890.24	($387,133.54)	$2,193,756.70	($3,057,955)	($38,450)	$0	0	0	0	($902,648)	$0	($902,648)		($902,648)	($63,425)
20	350,000	182,500	$2,684,125.85	($402,618.88)	$2,281,506.97	($3,363,750)	($39,988)	$0	0	0	0	($1,122,231)	$0	($1,122,231)		($1,122,231)	($68,569)

- Water production rate = 1,000 bbl/d



CoProduction
Horizontal well in upper formation to produce gas
Horizontal well below GWC to control the contact location
No new equipment

$3MM per horizontal well
Depreciation/amortization of facility is not considered as it is common to all cases
Depreciation/amortization will only be considered if and exclusive to newly acquired equipment

Acquisition:	$0			
Development:	$3,000,000			
Equipment:	$0	No new equipment		
Working Capital:	$0			
Evaluation Life:	-	Years		
Equipment Depreciation:	-	year (MACRS, time 0, half year)		
Salvage Value:	$0	EOY5		
Tax Rate:	40%			
Royalties:	15%			
Operating Costs:	($500,000)	@ Y1 @ escalate:		10%
Production (Y1-Y20):	200	MSCF/D		
Annual reduction:	-	MSCF/D		
Operating Days/Yr	350	days		
Unit Price:	$3.50	/MSCF/D		
Escalation:	4%			
Water disposal costs	$0.10	/bbl		
Gas/water separation costs	$0.10	/bbl		
Gas compression costs	$0.10	/mcf		
Minimum DCFROR:	15.00%			

Rate

Gas (mcf/d)	Water (bbl/d)
200	1000

Net Present Value
($8,400,252)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	70,000	365,000	$245,000.00	($36,750.00)	$208,250.00	($500,000)	($36,500)	$0	0		0	($328,250)	$0	($328,250)	($3,000,000)	($3,328,250)	($3,328,250)
1	70,000	365,000	$254,800.00	($38,220.00)	$216,580.00	($550,000)	($37,960)	$0	0	0	0	($371,380)	$0	($371,380)		($371,380)	($322,939)
2	70,000	365,000	$264,992.00	($39,748.80)	$225,243.20	($605,000)	($39,478)	$0	0	0	0	($419,235)	$0	($419,235)		($419,235)	($317,002)
3	70,000	365,000	$275,591.68	($41,338.75)	$234,252.93	($665,500)	($41,058)	$0	0	0	0	($472,305)	$0	($472,305)		($472,305)	($310,548)
4	70,000	365,000	$286,615.35	($42,992.30)	$243,623.05	($732,050)	($42,700)	$0	0	0	0	($531,127)	$0	($531,127)		($531,127)	($303,673)
5	70,000	365,000	$298,079.96	($44,711.99)	$253,367.97	($805,255)	($44,408)	$0	0	0	0	($596,295)	$0	($596,295)		($596,295)	($296,464)
6	70,000	365,000	$310,003.16	($46,500.47)	$263,502.69	($885,781)	($46,184)	$0	0	0	0	($668,462)	$0	($668,462)		($668,462)	($288,995)
7	70,000	365,000	$322,403.29	($48,360.49)	$274,042.79	($974,359)	($48,032)	$0	0	0	0	($748,347)	$0	($748,347)		($748,347)	($281,331)
8	70,000	365,000	$335,299.42	($50,294.91)	$285,004.50	($1,071,794)	($49,953)	$0	0	0	0	($836,743)	$0	($836,743)		($836,743)	($273,533)
9	70,000	365,000	$348,711.39	($52,306.71)	$296,404.68	($1,178,974)	($51,951)	$0	0	0	0	($934,520)	$0	($934,520)		($934,520)	($265,649)
10	70,000	365,000	$362,659.85	($54,398.98)	$308,260.87	($1,296,871)	($54,029)	$0	0	0	0	($1,042,639)	$0	($1,042,639)		($1,042,639)	($257,724)
11	70,000	365,000	$377,166.24	($56,574.94)	$320,591.31	($1,426,558)	($56,190)	$0	0	0	0	($1,162,157)	$0	($1,162,157)		($1,162,157)	($249,798)
12	70,000	365,000	$392,252.89	($58,837.93)	$333,414.96	($1,569,214)	($58,438)	$0	0	0	0	($1,294,237)	$0	($1,294,237)		($1,294,237)	($241,902)
13	70,000	365,000	$407,943.01	($61,191.45)	$346,751.56	($1,726,136)	($60,775)	$0	0	0	0	($1,440,159)	$0	($1,440,159)		($1,440,159)	($234,066)
14	70,000	365,000	$424,260.73	($63,639.11)	$360,621.62	($1,898,749)	($63,206)	$0	0	0	0	($1,601,334)	$0	($1,601,334)		($1,601,334)	($226,314)
15	70,000	365,000	$441,231.16	($66,184.67)	$375,046.49	($2,088,624)	($65,734)	$0	0	0	0	($1,779,312)	$0	($1,779,312)		($1,779,312)	($218,668)
16	70,000	365,000	$458,880.41	($68,832.06)	$390,048.34	($2,297,486)	($68,364)	$0	0	0	0	($1,975,802)	$0	($1,975,802)		($1,975,802)	($211,144)
17	70,000	365,000	$477,235.62	($71,585.34)	$405,650.28	($2,527,235)	($71,098)	$0	0	0	0	($2,192,683)	$0	($2,192,683)		($2,192,683)	($203,757)
18	70,000	365,000	$496,325.05	($74,448.76)	$421,876.29	($2,779,959)	($73,942)	$0	0	0	0	($2,432,025)	$0	($2,432,025)		($2,432,025)	($196,520)
19	70,000	365,000	$516,178.05	($77,426.71)	$438,751.34	($3,057,955)	($76,900)	$0	0	0	0	($2,696,103)	$0	($2,696,103)		($2,696,103)	($189,443)
20	70,000	365,000	$536,825.17	($80,523.78)	$456,301.39	($3,363,750)	($79,976)	$0	0	0	0	($2,987,425)	$0	($2,987,425)		($2,987,425)	($182,532)

Rate

Gas (mcf/d)	Water (bbl/d)
400	1000

Net Present Value
($4,581,127)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	140,000	365,000	$490,000.00	($73,500.00)	$416,500.00	($500,000)	($36,500)	$0	0		0	($120,000)	$0	($120,000)	($3,000,000)	($3,120,000)	($3,120,000)
1	140,000	365,000	$509,600.00	($76,440.00)	$433,160.00	($550,000)	($37,960)	$0	0	0	0	($154,800)	$0	($154,800)		($154,800)	($134,609)
2	140,000	365,000	$529,984.00	($79,497.60)	$450,486.40	($605,000)	($39,478)	$0	0	0	0	($193,992)	$0	($193,992)		($193,992)	($146,686)
3	140,000	365,000	$551,183.36	($82,677.50)	$468,505.86	($665,500)	($41,058)	$0	0	0	0	($238,052)	$0	($238,052)		($238,052)	($156,523)
4	140,000	365,000	$573,230.69	($85,984.60)	$487,246.09	($732,050)	($42,700)	$0	0	0	0	($287,504)	$0	($287,504)		($287,504)	($164,381)
5	140,000	365,000	$596,159.92	($89,423.99)	$506,735.93	($805,255)	($44,408)	$0	0	0	0	($342,927)	$0	($342,927)		($342,927)	($170,495)
6	140,000	365,000	$620,006.32	($93,000.95)	$527,005.37	($885,781)	($46,184)	$0	0	0	0	($404,959)	$0	($404,959)		($404,959)	($175,075)
7	140,000	365,000	$644,806.57	($96,720.99)	$548,085.59	($974,359)	($48,032)	$0	0	0	0	($474,304)	$0	($474,304)		($474,304)	($178,309)
8	140,000	365,000	$670,598.83	($100,589.83)	$570,009.01	($1,071,794)	($49,953)	$0	0	0	0	($551,738)	$0	($551,738)		($551,738)	($180,364)
8.84	117,600	365,000	$582,170.35	($87,325.55)	$494,844.80	($975,350)	($51,626)	$0	0	0	0	($532,131)	$0	($532,131)		($532,131)	($154,686)

Rate

Gas (mcf/d)	Water (bbl/d)
600	1000

Net Present Value

($2,963,843)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounte
0	210,000	365,000	$735,000.00	($110,250.00)	$624,750.00	($500,000)	($36,500)	$0	0		0	$88,250	####	$52,950	($3,000,000)	($2,947,050)	($2,947,050)
1	210,000	365,000	$764,400.00	($114,660.00)	$649,740.00	($550,000)	($37,960)	$0	0	0	0	$61,780	####	$37,068		$37,068	$32,233
2	210,000	365,000	$794,976.00	($119,246.40)	$675,729.60	($605,000)	($39,478)	$0	0	0	0	$31,251	####	$18,751		$18,751	$14,178
3	210,000	365,000	$826,775.04	($124,016.26)	$702,758.78	($665,500)	($41,058)	$0	0	0	0	($3,799)	$0	($3,799)		($3,799)	($2,498)
4	210,000	365,000	$859,846.04	($128,976.91)	$730,869.14	($732,050)	($42,700)	$0	0	0	0	($43,881)	$0	($43,881)		($43,881)	($25,089)
4.75	157,500	365,000	$664,135.91	($99,620.39)	$564,515.52	($589,721)	($43,975)	$0	0	0	0	($69,180)	$0	($69,180)		($69,180)	($35,618)

Rate

Gas (mcf/d)	Water (bbl/d)
800	1000

Net Present Value

($2,368,686)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounte
0	280,000	365,000	$980,000.00	($147,000.00)	$833,000.00	($500,000)	($36,500)	$0	0		0	$296,500	####	$177,900	($3,000,000)	($2,822,100)	($2,822,100)
1	280,000	365,000	$1,019,200.00	($152,880.00)	$866,320.00	($550,000)	($37,960)	$0	0	0	0	$278,360	####	$167,016		$167,016	$145,231
2	280,000	365,000	$1,059,968.00	($158,995.20)	$900,972.80	($605,000)	($39,478)	$0	0	0	0	$256,494	####	$153,897		$153,897	$116,368
3	280,000	365,000	$1,102,366.72	($165,355.01)	$937,011.71	($665,500)	($41,058)	$0	0	0	0	$230,454	####	$138,273		$138,273	$90,916
4	280,000	365,000	$1,146,461.39	($171,969.21)	$974,492.18	($732,050)	($42,700)	$0	0	0	0	$199,742	####	$119,845		$119,845	$68,522
4.67	187,600	365,000	$788,581.48	($118,287.22)	$670,294.26	($522,816)	($43,837)	$0	0	0	0	$103,642	####	$62,185		$62,185	$32,376

Rate

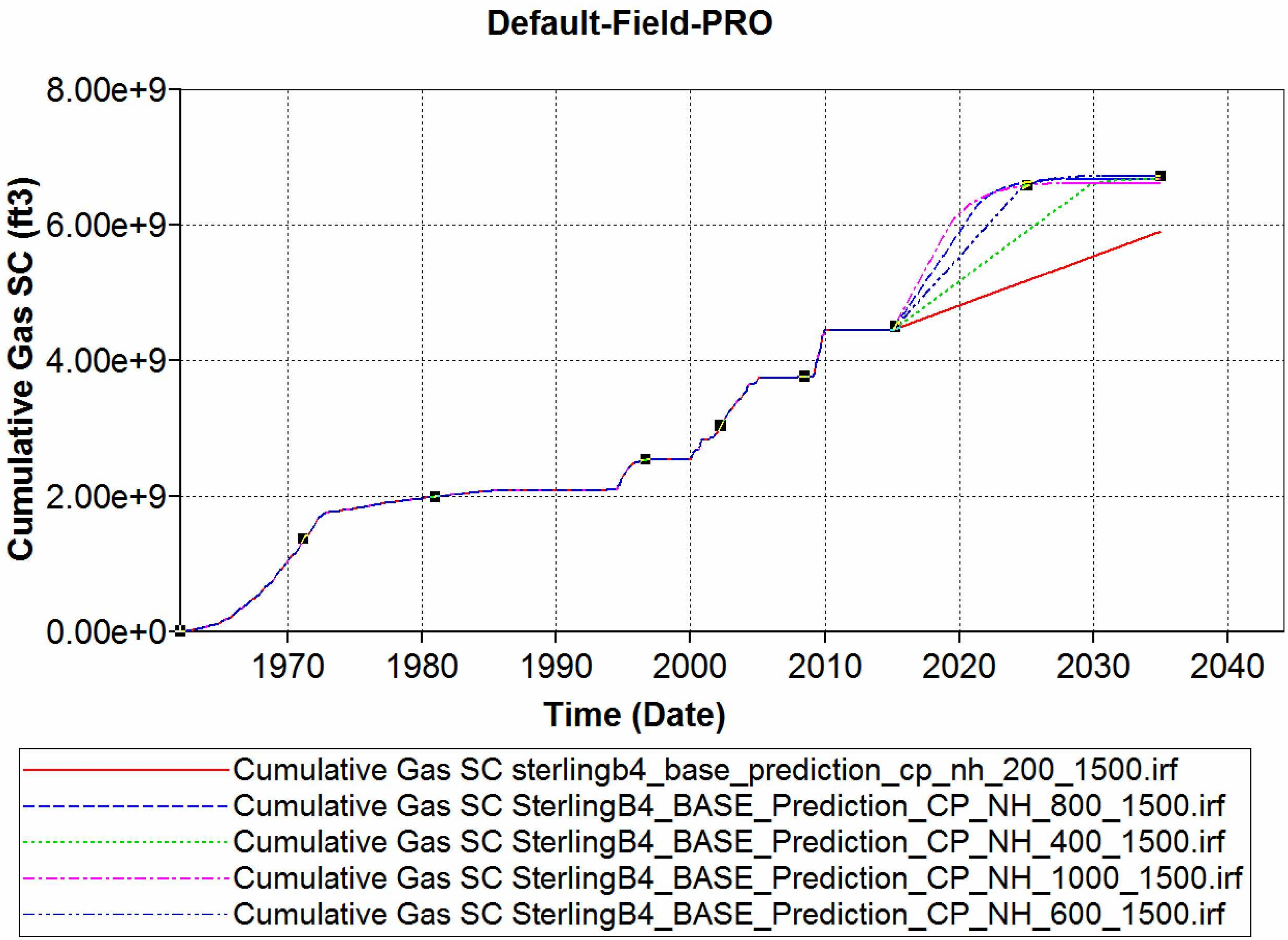
Gas (mcf/d)	Water (bbl/d)
1000	1000

Net Present Value

($1,921,120)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	350,000	365,000	$1,225,000.00	($183,750.00)	$1,041,250.00	($500,000)	($36,500)	$0	0		0	$504,750	####	$302,850	($3,000,000)	($2,697,150)	($2,697,150)
1	350,000	365,000	$1,274,000.00	($191,100.00)	$1,082,900.00	($550,000)	($37,960)	$0	0	0	0	$494,940	####	$296,964		$296,964	$258,230
2	350,000	365,000	$1,324,960.00	($198,744.00)	$1,126,216.00	($605,000)	($39,478)	$0	0	0	0	$481,738	####	$289,043		$289,043	$218,558
3	350,000	365,000	$1,377,958.40	($206,693.76)	$1,171,264.64	($665,500)	($41,058)	$0	0	0	0	$464,707	####	$278,824		$278,824	$183,331
3.75	262,500	365,000	$1,064,320.37	($159,648.06)	$904,672.32	($536,110)	($42,283)	$0	0	0	0	$326,279	####	$195,768		$195,768	$115,911

- Water production rate = 1,500 bbl/d



CoProduction
Horizontal well in upper formation to produce gas
Horizontal well below GWC to control the contact location
No new equipment

$3MM per horizontal well
Depreciation/amortization of facility is not considered as it is common to all cases
Depreciation/amortization will only be considered if and exclusive to newly acquired equipment

Acquisition:	$0			
Development:	$3,000,000			
Equipment:	$0	No new equipment		
Working Capital:	$0			
Evaluation Life:	-	Years		
Equipment Depreciation:	-	year (MACRS, time 0, half year)		
Salvage Value:	$0	EOY5		
Tax Rate:	40%			
Royalties:	15%			
Operating Costs:	($500,000)	@ Y1 @ escalate:		10%
Production (Y1-Y20):	200	MSCF/D		
Annual reduction:	-	MSCF/D		
Operating Days/Yr	350	days		
Unit Price:	$3.50	/MSCF/D		
Escalation:	4%			
Water disposal costs	$0.10	/bbl		
Gas/water separation costs	$0.10	/bbl		
Gas compression costs	$0.10	/mcf		
Minimum DCFROR:	15.00%			

Rate

Gas (mcf/d)	Water (bbl/d)
200	1500

Net Present Value
($8,567,948)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	70,000	547,500	$245,000.00	($36,750.00)	$208,250.00	($500,000)	($54,750)	$0	0		0	($346,500)	$0	($346,500)	($3,000,000)	($3,346,500)	($3,346,500)
1	70,000	547,500	$254,800.00	($38,220.00)	$216,580.00	($550,000)	($56,940)	$0	0	0	0	($390,360)	$0	($390,360)		($390,360)	($339,443)
2	70,000	547,500	$264,992.00	($39,748.80)	$225,243.20	($605,000)	($59,218)	$0	0	0	0	($438,974)	$0	($438,974)		($438,974)	($331,928)
3	70,000	547,500	$275,591.68	($41,338.75)	$234,252.93	($665,500)	($61,586)	$0	0	0	0	($492,833)	$0	($492,833)		($492,833)	($324,046)
4	70,000	547,500	$286,615.35	($42,992.30)	$243,623.05	($732,050)	($64,050)	$0	0	0	0	($552,477)	$0	($552,477)		($552,477)	($315,880)
5	70,000	547,500	$298,079.96	($44,711.99)	$253,367.97	($805,255)	($66,612)	$0	0	0	0	($618,499)	$0	($618,499)		($618,499)	($307,503)
6	70,000	547,500	$310,003.16	($46,500.47)	$263,502.69	($885,781)	($69,276)	$0	0	0	0	($691,554)	$0	($691,554)		($691,554)	($298,978)
7	70,000	547,500	$322,403.29	($48,360.49)	$274,042.79	($974,359)	($72,047)	$0	0	0	0	($772,363)	$0	($772,363)		($772,363)	($290,360)
8	70,000	547,500	$335,299.42	($50,294.91)	$285,004.50	($1,071,794)	($74,929)	$0	0	0	0	($861,719)	$0	($861,719)		($861,719)	($281,697)
9	70,000	547,500	$348,711.39	($52,306.71)	$296,404.68	($1,178,974)	($77,926)	$0	0	0	0	($960,495)	$0	($960,495)		($960,495)	($273,033)
10	70,000	547,500	$362,659.85	($54,398.98)	$308,260.87	($1,296,871)	($81,043)	$0	0	0	0	($1,069,654)	$0	($1,069,654)		($1,069,654)	($264,402)
11	70,000	547,500	$377,166.24	($56,574.94)	$320,591.31	($1,426,558)	($84,285)	$0	0	0	0	($1,190,252)	$0	($1,190,252)		($1,190,252)	($255,837)
12	70,000	547,500	$392,252.89	($58,837.93)	$333,414.96	($1,569,214)	($87,657)	$0	0	0	0	($1,323,456)	$0	($1,323,456)		($1,323,456)	($247,363)
13	70,000	547,500	$407,943.01	($61,191.45)	$346,751.56	($1,726,136)	($91,163)	$0	0	0	0	($1,470,547)	$0	($1,470,547)		($1,470,547)	($239,005)
14	70,000	547,500	$424,260.73	($63,639.11)	$360,621.62	($1,898,749)	($94,809)	$0	0	0	0	($1,632,937)	$0	($1,632,937)		($1,632,937)	($230,781)
15	70,000	547,500	$441,231.16	($66,184.67)	$375,046.49	($2,088,624)	($98,602)	$0	0	0	0	($1,812,179)	$0	($1,812,179)		($1,812,179)	($222,707)
16	70,000	547,500	$458,880.41	($68,832.06)	$390,048.34	($2,297,486)	($102,546)	$0	0	0	0	($2,009,984)	$0	($2,009,984)		($2,009,984)	($214,796)
17	70,000	547,500	$477,235.62	($71,585.34)	$405,650.28	($2,527,235)	($106,648)	$0	0	0	0	($2,228,232)	$0	($2,228,232)		($2,228,232)	($207,060)
18	70,000	547,500	$496,325.05	($74,448.76)	$421,876.29	($2,779,959)	($110,913)	$0	0	0	0	($2,468,996)	$0	($2,468,996)		($2,468,996)	($199,508)
19	70,000	547,500	$516,178.05	($77,426.71)	$438,751.34	($3,057,955)	($115,350)	$0	0	0	0	($2,734,553)	$0	($2,734,553)		($2,734,553)	($192,144)
20	70,000	547,500	$536,825.17	($80,523.78)	$456,301.39	($3,363,750)	($119,964)	$0	0	0	0	($3,027,413)	$0	($3,027,413)		($3,027,413)	($184,976)

Rate

Gas (mcf/d)	Water (bbl/d)
400	1500

Net Present Value
($6,260,528)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	140,000	547,500	$490,000.00	($73,500.00)	$416,500.00	($500,000)	($54,750)	$0	0		0	($138,250)	$0	($138,250)	($3,000,000)	($3,138,250)	($3,138,250)
1	140,000	547,500	$509,600.00	($76,440.00)	$433,160.00	($550,000)	($56,940)	$0	0	0	0	($173,780)	$0	($173,780)		($173,780)	($151,113)
2	140,000	547,500	$529,984.00	($79,497.60)	$450,486.40	($605,000)	($59,218)	$0	0	0	0	($213,731)	$0	($213,731)		($213,731)	($161,611)
3	140,000	547,500	$551,183.36	($82,677.50)	$468,505.86	($665,500)	($61,586)	$0	0	0	0	($258,580)	$0	($258,580)		($258,580)	($170,021)
4	140,000	547,500	$573,230.69	($85,984.60)	$487,246.09	($732,050)	($64,050)	$0	0	0	0	($308,854)	$0	($308,854)		($308,854)	($176,588)
5	140,000	547,500	$596,159.92	($89,423.99)	$506,735.93	($805,255)	($66,612)	$0	0	0	0	($365,131)	$0	($365,131)		($365,131)	($181,535)
6	140,000	547,500	$620,006.32	($93,000.95)	$527,005.37	($885,781)	($69,276)	$0	0	0	0	($428,051)	$0	($428,051)		($428,051)	($185,058)
7	140,000	547,500	$644,806.57	($96,720.99)	$548,085.59	($974,359)	($72,047)	$0	0	0	0	($498,320)	$0	($498,320)		($498,320)	($187,337)
8	140,000	547,500	$670,598.83	($100,589.83)	$570,009.01	($1,071,794)	($74,929)	$0	0	0	0	($576,715)	$0	($576,715)		($576,715)	($188,529)
9	140,000	547,500	$697,422.79	($104,613.42)	$592,809.37	($1,178,974)	($77,926)	$0	0	0	0	($664,091)	$0	($664,091)		($664,091)	($188,776)
10	140,000	547,500	$725,319.70	($108,797.95)	$616,521.74	($1,296,871)	($81,043)	$0	0	0	0	($761,393)	$0	($761,393)		($761,393)	($188,205)

11	140,000	547,500	$754,332.49	($113,149.87)	$641,182.61	($1,426,558)	($84,285)	$0	0	0	0	($869,661)	$0	($869,661)		($869,661)	($186,928)
12	140,000	547,500	$784,505.79	($117,675.87)	$666,829.92	($1,569,214)	($87,657)	$0	0	0	0	($990,041)	$0	($990,041)		($990,041)	($185,046)
13	140,000	547,500	$815,886.02	($122,382.90)	$693,503.12	($1,726,136)	($91,163)	$0	0	0	0	($1,123,795)	$0	($1,123,795)		($1,123,795)	($182,648)
14	140,000	547,500	$848,521.46	($127,278.22)	$721,243.24	($1,898,749)	($94,809)	$0	0	0	0	($1,272,315)	$0	($1,272,315)		($1,272,315)	($179,815)
15	140,000	547,500	$882,462.32	($132,369.35)	$750,092.97	($2,088,624)	($98,602)	$0	0	0	0	($1,437,133)	$0	($1,437,133)		($1,437,133)	($176,616)
16	140,000	547,500	$917,760.81	($137,664.12)	$780,096.69	($2,297,486)	($102,546)	$0	0	0	0	($1,619,936)	$0	($1,619,936)		($1,619,936)	($173,114)
17	140,000	547,500	$954,471.24	($143,170.69)	$811,300.56	($2,527,235)	($106,648)	$0	0	0	0	($1,822,582)	$0	($1,822,582)		($1,822,582)	($169,365)
17.51	71,400	547,500	$496,615.22	($74,492.28)	$422,122.94	($1,353,088)	($108,802)	$0	0	0	0	($1,039,767)	$0	($1,039,767)		($1,039,767)	($89,974)

Rate

Gas (mcf/d) 600

Water (bbl/d) 1500

Net Present Value

($3,983,803)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	210,000	547,500	$735,000.00	($110,250.00)	$624,750.00	($500,000)	($54,750)	$0	0		0	$70,000	####	$42,000	($3,000,000)	($2,958,000)	($2,958,000)
1	210,000	547,500	$764,400.00	($114,660.00)	$649,740.00	($550,000)	($56,940)	$0	0	0	0	$42,800	####	$25,680		$25,680	$22,330
2	210,000	547,500	$794,976.00	($119,246.40)	$675,729.60	($605,000)	($59,218)	$0	0	0	0	$11,512	####	$6,907		$6,907	$5,223
3	210,000	547,500	$826,775.04	($124,016.26)	$702,758.78	($665,500)	($61,586)	$0	0	0	0	($24,328)	$0	($24,328)		($24,328)	($15,996)
4	210,000	547,500	$859,846.04	($128,976.91)	$730,869.14	($732,050)	($64,050)	$0	0	0	0	($65,231)	$0	($65,231)		($65,231)	($37,296)
5	210,000	547,500	$894,239.88	($134,135.98)	$760,103.90	($805,255)	($66,612)	$0	0	0	0	($111,763)	$0	($111,763)		($111,763)	($55,566)
6	210,000	547,500	$930,009.48	($139,501.42)	$790,508.06	($885,781)	($69,276)	$0	0	0	0	($164,549)	$0	($164,549)		($164,549)	($71,139)
7	210,000	547,500	$967,209.86	($145,081.48)	$822,128.38	($974,359)	($72,047)	$0	0	0	0	($224,277)	$0	($224,277)		($224,277)	($84,314)
8	210,000	547,500	$1,005,898.25	($150,884.74)	$855,013.51	($1,071,794)	($74,929)	$0	0	0	0	($291,710)	$0	($291,710)		($291,710)	($95,361)
9	210,000	547,500	$1,046,134.18	($156,920.13)	$889,214.05	($1,178,974)	($77,926)	$0	0	0	0	($367,686)	$0	($367,686)		($367,686)	($104,519)
10	210,000	547,500	$1,087,979.55	($163,196.93)	$924,782.62	($1,296,871)	($81,043)	$0	0	0	0	($453,132)	$0	($453,132)		($453,132)	($112,007)
11	210,000	547,500	$1,131,498.73	($169,724.81)	$961,773.92	($1,426,558)	($84,285)	$0	0	0	0	($549,070)	$0	($549,070)		($549,070)	($118,019)
12	210,000	547,500	$1,176,758.68	($176,513.80)	$1,000,244.88	($1,569,214)	($87,657)	$0	0	0	0	($656,626)	$0	($656,626)		($656,626)	($122,728)
13	210,000	547,500	$1,223,829.03	($183,574.35)	$1,040,254.67	($1,726,136)	($91,163)	$0	0	0	0	($777,044)	$0	($777,044)		($777,044)	($126,291)
13.84	176,400	547,500	$1,062,448.88	($159,367.33)	$903,081.54	($1,570,811)	($94,216)	$0	0	0	0	($761,946)	$0	($761,946)		($761,946)	($110,120)

Rate

Gas (mcf/d) 800

Water (bbl/d) 1500

Net Present Value

($2,522,541)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	280,000	547,500	$980,000.00	($147,000.00)	$833,000.00	($500,000)	($54,750)	$0	0		0	$278,250	####	$166,950	($3,000,000)	($2,833,050)	($2,833,050)
1	280,000	547,500	$1,019,200.00	($152,880.00)	$866,320.00	($550,000)	($56,940)	$0	0	0	0	$259,380	####	$155,628		$155,628	$135,329
2	280,000	547,500	$1,059,968.00	($158,995.20)	$900,972.80	($605,000)	($59,218)	$0	0	0	0	$236,755	####	$142,053		$142,053	$107,413
3	280,000	547,500	$1,102,366.72	($165,355.01)	$937,011.71	($665,500)	($61,586)	$0	0	0	0	$209,925	####	$125,955		$125,955	$82,818
4	280,000	547,500	$1,146,461.39	($171,969.21)	$974,492.18	($732,050)	($64,050)	$0	0	0	0	$178,392	####	$107,035		$107,035	$61,198
5	280,000	547,500	$1,192,319.84	($178,847.98)	$1,013,471.87	($805,255)	($66,612)	$0	0	0	0	$141,605	####	$84,963		$84,963	$42,242
6	280,000	547,500	$1,240,012.64	($186,001.90)	$1,054,010.74	($885,781)	($69,276)	$0	0	0	0	$98,954	####	$59,372		$59,372	$25,668
7	280,000	547,500	$1,289,613.14	($193,441.97)	$1,096,171.17	($974,359)	($72,047)	$0	0	0	0	$49,765	####	$29,859		$29,859	$11,225
8	280,000	547,500	$1,341,197.67	($201,179.65)	$1,140,018.02	($1,071,794)	($74,929)	$0	0	0	0	($6,706)	$0	($6,706)		($6,706)	($2,192)
9	280,000	547,500	$1,394,845.58	($209,226.84)	$1,185,618.74	($1,178,974)	($77,926)	$0	0	0	0	($71,281)	$0	($71,281)		($71,281)	($20,263)
10	280,000	547,500	$1,450,639.40	($217,595.91)	$1,233,043.49	($1,296,871)	($81,043)	$0	0	0	0	($144,871)	$0	($144,871)		($144,871)	($35,810)

11	280,000	547,500	$1,508,664.98	($226,299.75)	$1,282,365.23	($1,426,558)	($84,285)	$0	0	0	0	($228,478)	$0	($228,478)		($228,478)	($49,110)
11.76	212,800	547,500	$1,181,276.97	($177,191.55)	$1,004,085.43	($1,165,632)	($86,835)	$0	0	0	0	($248,382)	$0	($248,382)		($248,382)	($48,008)

Rate

Gas (mcf/d)	Water (bbl/d)
1000	1500

Net Present Value

($1,518,292)

Year	Upper Gas Production (mcf)	Water Production (bbl)	Revenue	Royalties	Net Revenue	Operations	H2O Disposal	Depletion	IDCs	Depreciation	Amortization	Taxable	Tax	Net Income	Capital Costs	Cash flow	Discounted
0	350,000	547,500	$1,225,000.00	($183,750.00)	$1,041,250.00	($500,000)	($54,750)	$0	0		0	$486,500	####	$291,900	($3,000,000)	($2,708,100)	($2,708,100)
1	350,000	547,500	$1,274,000.00	($191,100.00)	$1,082,900.00	($550,000)	($56,940)	$0	0	0	0	$475,960	####	$285,576		$285,576	$248,327
2	350,000	547,500	$1,324,960.00	($198,744.00)	$1,126,216.00	($605,000)	($59,218)	$0	0	0	0	$461,998	####	$277,199		$277,199	$209,602
3	350,000	547,500	$1,377,958.40	($206,693.76)	$1,171,264.64	($665,500)	($61,586)	$0	0	0	0	$444,178	####	$266,507		$266,507	$175,233
4	350,000	547,500	$1,433,076.74	($214,961.51)	$1,218,115.23	($732,050)	($64,050)	$0	0	0	0	$422,015	####	$253,209		$253,209	$144,773
5	350,000	547,500	$1,490,399.81	($223,559.97)	$1,266,839.83	($805,255)	($66,612)	$0	0	0	0	$394,973	####	$236,984		$236,984	$117,823
6	350,000	547,500	$1,550,015.80	($232,502.37)	$1,317,513.43	($885,781)	($69,276)	$0	0	0	0	$362,457	####	$217,474		$217,474	$94,020
7	350,000	547,500	$1,612,016.43	($241,802.46)	$1,370,213.97	($974,359)	($72,047)	$0	0	0	0	$323,808	####	$194,285		$194,285	$73,039
8	350,000	547,500	$1,676,497.09	($251,474.56)	$1,425,022.52	($1,071,794)	($74,929)	$0	0	0	0	$278,299	####	$166,979		$166,979	$54,586
9	350,000	547,500	$1,743,556.97	($261,533.55)	$1,482,023.42	($1,178,974)	($77,926)	$0	0	0	0	$225,123	####	$135,074		$135,074	$38,396
10	350,000	547,500	$1,813,299.25	($271,994.89)	$1,541,304.36	($1,296,871)	($81,043)	$0	0	0	0	$163,390	####	$98,034		$98,034	$24,232
10.84	294,000	547,500	$1,574,188.64	($236,128.30)	$1,338,060.34	($1,180,174)	($83,758)	$0	0	0	0	$74,129	####	$44,477		$44,477	$9,776